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(U.S.) Tennessee Valley Authority
Muscle Shoals, AL

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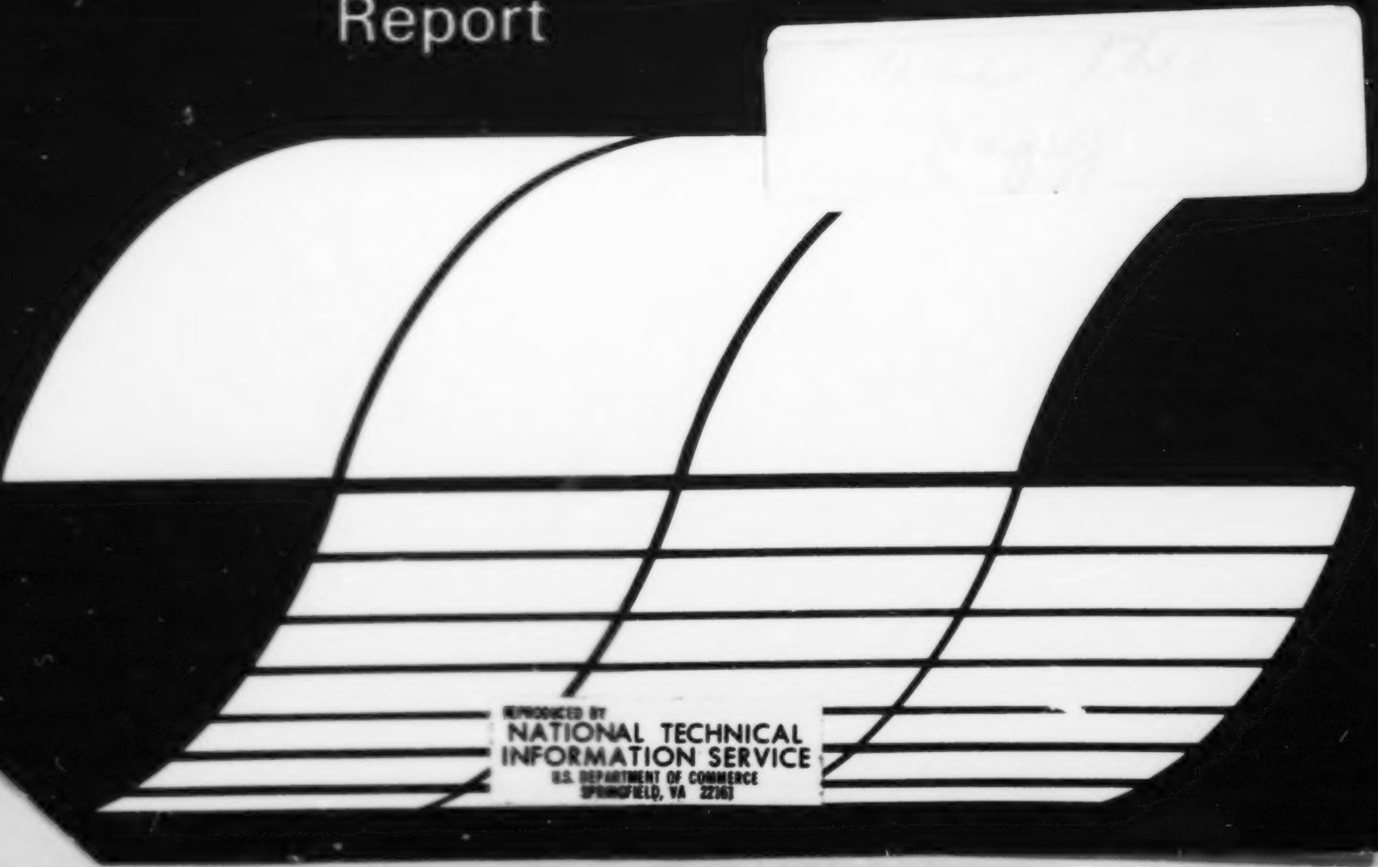
Phase II Applicability Study

Interagency Energy/Environment R&D Program Report



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16. ABSTRACT

The North Atlantic Treaty Organization Committee on the Challenges of Modern Society (NATO-CCMS) Flue Gas Desulfurization (FGD) Study Group prepared status reports on 12 FGD processes. Results of this work are summarized in NATO Report No. 95 titled "Flue Gas Desulfurization Pilot Study Phase I - Survey of Major Installations - Summary of Survey Reports on Flue Gas Desulfurization Processes."

The Phase I reports were reviewed by the NATO-CCMS delegates in April 1978 and nine of the processes were selected for comparative economic evaluations as Phase II of the study. The purpose of the Phase II study is to provide procedures and technical and economic data for the selection of FGD processes for specific applications. The study consists of technical feasibility and economic evaluations developed by the U.S. Tennessee Valley Authority (TVA) and a decision-chart selection procedure developed by PEDCo Environmental, Inc.

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FLUE GAS DESULFURIZATION PILOT STUDY

PHASE II - APPLICABILITY STUDY

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Washington, D.C. 20460
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FOREWORD

Under the auspices of the North Atlantic Treaty Organization's Committee for the Challenges to Modern Society (NATO-CCMS), a two phase study of Flue Gas Desulfurization was conducted.

The rapid evolution of flue gas desulfurization technology along with increasing interest in this technology for reducing sulfur dioxide emissions prompted the NATO-CCMS to form a Study Group to assess and summarize information on these systems. This study initiated early in 1977 at a meeting of the member countries' delegates in London. The United States through its Environmental Protection Agency was the lead or pilot country with Norway and the Federal Republic of Germany the co-pilot countries. This study group met at approximately 6-month intervals to review progress, comment on completed work, and plan the succeeding steps.

The initial phase of this study consisted of a survey of existing FGD systems used on larger combustion processes in the NATO countries and Japan. Twelve FGD systems were surveyed and reports summarizing their status were prepared - NATO-CCMS Report No. 95.

This report comprises the second phase of this study, also built upon the early survey results by studying the applicability of nine FGD processes for typical North American and European fuels.

ACKNOWLEDGMENT

This report was prepared by the Flue Gas Desulfurization Study Group of the NATO Committee on the Challenges of Modern Society. Mr. Frank T. Princiotta of the U.S. Environmental Protection Agency served as chairman. Acknowledgment should be given to the U.S. Tennessee Valley Authority (TVA) and PEDCo Environmental, Inc., for their major role in preparing early drafts of the report. TVA and PEDCo prepared this report to the specific guidelines of the committee; ultimately the committee reviewed, revised, and approved the publication of the report. The members of the study group were:

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PREFACE

The North Atlantic Treaty Organization Committee on the Challenges of Modern Society (NATO-CCMS) Flue Gas Desulfurization (FGD) Study Group prepared status reports on 12 FGD processes. Results of this work are summarized in NATO Report No. 95 titled "Flue Gas Desulfurization Pilot Study Phase I - Survey of Major Installations - Summary of Survey Reports on Flue Gas Desulfurization Processes."

The Phase I reports were reviewed by the NATO-CCMS delegates in April 1978 and nine of the processes were selected for comparative economic evaluations as Phase II of the study. The purpose of the Phase II study is to provide procedures and technical and economic data for the selection of FGD processes for specific applications. The study consists of technical feasibility and economic evaluations developed by the U.S. Tennessee Valley Authority (TVA) and a decision-chart selection procedure developed by PEDCo Environmental, Inc.

The basis of the economic evaluations is an FGD system for a new Midwestern U.S. 500-MW power plant. The FGD system is designed for removal of 90% of the SO_2 in the flue gas. Six fuels, consisting of bituminous coals, lignite, and oil, are evaluated. Scaling procedures are provided for projection of costs for other conditions such as different power plant sizes and fuels with different sulfur levels.

The decision-chart system consists of an elimination procedure which rates the applicability of the processes relating the FGD process characteristics to specific site conditions. The system is an initial selection procedure which allows FGD selection efforts to be focused on the most promising processes.

DISCLAIMER

This report was prepared by the Tennessee Valley Authority and has been reviewed by the Office of Environmental Energy and Technology, U.S. Environmental Protection Agency, and approved for publication. It has also been reviewed and agreed to in principle by the NATO-CCMS Flue Gas Desulfurization (FGD) Study Group. Approval does not signify that the contents necessarily reflect the views and policies of the Tennessee Valley Authority or the U.S. Environmental Protection Agency, or of any representative of the NATO-CCMS FGD Study Group, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

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ABBREVIATIONS AND CONVERSION FACTORS

ABBREVIATIONS

aft^3	actual cubic feet
bbl	42 U.S. gallon barrel
Btu	British thermal unit
cal	calorie
c	U.S. cents
cm	centimeter
°C	degree Celsius
°F	degree Fahrenheit
ESP	electrostatic precipitator
FD	forced draft
FGD	flue gas desulfurization
FRP	fiberglass reinforced polyester
ft	foot
g	gram
gal	U.S. gallon
gpm	U.S. gallon per minute
ha	hectares
hp	horsepower
hr	hour
ID	induced draft
in.	inch
in. head	inches H_2O head
j	joule
k	thousand (kilo-)
kg	kilogram
kW	kilowatt
kWh	kilowatthour
L/G	liquid to gas
lb	pound
M	million (10^6)(mega-)
m	meter
meq	milliequivalent
mm	millimeter
mol	mole
MW	megawatt
Nm^3	normal cubic meter (at 0°C)
NO_x	nitrogen oxides
pa	pascal
ppm	parts per million
psi	pounds per square inch
psig	pounds per square inch, gauge
rpm	revolutions per minute
$	U.S. dollar
sec	second
sft^3	standard cubic foot (60°F)
SO_x	sulfur oxides
SS	stainless steel
TCA	Turbulent Contact Absorber (TM)
TM	registered trademark
tons	short tons

CONVERSION FACTORS

To convert from English units	To	Multiply by
acre	hectare	0.405
barrels of oil	liters	158.97
British thermal unit	kilocalories	0.252
degrees Fahrenheit-32	degrees Celsius	0.555
feet	meters	0.3048
square feet	square meters	0.093
cubic feet	cubic meters	0.0283
gallons[a]	liters	3.785
grains (troy)	grams	0.0648
grains per cubic foot	grams per cubic meters	2.288
inches H_2O head	pascals	249
pounds	kilograms	0.4536
pounds per square inch	pascals	6895
miles	meters	1609
mills	U.S. dollars	0.001
short tons[b]	metric tons	0.907
standard cubic feet per minute (60°F)	normal cubic meters per hour (0°C)	1.608

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a. All gallons are expressed as U.S. gallons in this report.

b. All tons, including tons of sulfur, are expressed in short tons in this report.

NATO-CCMS

FLUE GAS DESULFURIZATION PILOT STUDY

PHASE II - APPLICABILITY STUDY

EXECUTIVE SUMMARY

INTRODUCTION

The Phase I reports on 12 flue gas desulfurization (FGD) processes for the North Atlantic Treaty Organization Committee on the Challenges of Modern Society (NATO-CCMS) FGD Study Group were reviewed by the NATO-CCMS delegates in April 1978 and 9 of the processes were selected for comparative economic evaluations as Phase II of the study. The purpose of the Phase II study is to provide procedures and technical and economic data for the selection of FGD processes for specific applications. The study consists of technical feasibility and economic evaluations developed by the U.S. Tennessee Valley Authority (TVA) and a decision-chart selection procedure developed by PEDCo Environmental, Inc.

The basis of the economic evaluations is an FGD system for a new Midwestern U.S. 500-MW power plant. The FGD system is designed for removal of 90% of the SO_2 in the flue gas. Six fuels, consisting of bituminous coals, lignite, and oil, are evaluated. Scaling procedures are provided for projection of costs for other conditions such as different power plant sizes and fuels with different sulfur levels.

The design and economic bases of this study differ from the Phase I study because of updated information and standardizations to provide comparable results between processes. The results of this study should be compared to the Phase I results with caution. It should also be recognized that the data are based on U.S. conditions and that simplifying assumptions are made in the design model. These factors must be borne in mind when using the cost comparisons. Site-specific conditions may substantially alter the cost relationships of the processes.

The decision-chart system consists of an elimination procedure which rates the applicability of the processes relating the FGD process characteristics to specific site conditions. The system is an initial selection procedure which allows FGD selection efforts to be focused on the most promising processes.

PROCESSES EVALUATED AND ACCURACY OF RESULTS

The nine process evaluations in this study are based on data from a number of sources. Because of differences in the stage of development and amount of information available, the accuracy ranges of the economic results differ. Stage of development is difficult to quantify and is not considered in these evaluations. The accuracy ranges can, however, be related to the amount of information available. Normally, actual investment costs may be expected to depart from those shown in the economic evaluation by a factor of 0.7 to 1.5. Because of the extensive information available for some of the processes evaluated, however, smaller ranges can be projected. The accuracy ranges of each process, based on the amount of information available, are shown in the tabulated results. The nine processes evaluated are discussed below.

Limestone Scrubbing with Untreated Sludge Waste Disposal

The process evaluated is a generic design based on extensive TVA data from prototype and operational facilities and on general industry information. It is an updated version of the process described in the Phase I report.

Lime Scrubbing with Untreated Sludge Waste Disposal

The process evaluted is a generic design based on TVA data from prototype studies and on general industry information. It is also an updated version of the process reported in the Phase I report.

Double-Alkali Scrubbing with Untreated Sludge Waste Disposal

The process evaluated is a generic design based on prototype tests of system components. The process is an updated version of the process reported in the Phase I report.

Seawater Scrubbing with Ocean Disposal of Oxidized Waste

The process evaluated is based on the Flakt-Hydro process in operation on industrial boilers (of 50-MW total equivalent capacity) at Porsgrunn, Norway. Information was obtained from the Phase I report with supplemental data provided by the Foundation of Scientific and Industrial Research at the University of Trondheim, Norway, and A/S Norsk Viftefabrikk, Oslo, Norway. Because the process assumes that only seawater from the power plant condensers is used in the scrubbers, the 3.5% and 2.0% sulfur coals are not evaluated.

Lime Scrubbing with Oxidation and Dewatered Gypsum Waste Disposal

The process is based on the Saarberg-Holter process described in the Phase I report and additional information from Davy Powergas, Inc., the U.S. licensee. A 40-MW prototype was started up in 1974 and a 175-MW unit in 1979, both in West Germany.

Jet-Bubbling Limestone Scrubbing with Dewatered Gypsum Disposal

This process is based on the Chiyoda Thoroughbred 121 process that was developed from the Chiyoda Thoroughbred 101 process reported in the Phase I report. The process is based on information supplied by Chiyoda International Corporation.

Magnesium Oxide Scrubbing with Sulfuric Acid Production

The process evaluated is a generic design based on general industry information. It is an updated version, incorporating several process changes, of the process described in the Phase I report.

Sodium Sulfite Scrubbing with Sulfur and Sulfuric Acid Production

The process evaluated is based on Wellman-Lord scrubbing with regeneration of SO_2 and production of sulfuric acid. An alternate process based on Wellman-Lord/Allied Chemical technology for producing elemental sulfur is also included. It is an updated version of the process described in the Phase I report, incorporating several process changes. Additional information was provided by Davy Powergas, Inc., the Allied Chemical Company, and the Northern Indiana Public Service Company.

Dry Carbon Adsorption with Sulfur Production

The process evaluated is based on the Bergbau-Forschung Foster Wheeler RESOX® process using published information and additional information from the Foster Wheeler Corporation. The SO_x removal process was developed by Bergbau-Forschung GmbH. A 50-MW unit is operational at Lunen, West Germany. A Foster Wheeler RESOX® SO_2 reduction process is used to reduce the SO_2 to elemental sulfur using anthracite.

PREMISES FOR THE ECONOMIC EVALUATIONS

The design and economic premises used were developed by TVA and others for comparative FGD cost studies using representative U.S. power plant conditions. The base case is a frontal-fired, balanced-draft 500-MW power plant constructed in the period 1977 to 1980 in the U.S. Midwest for startup in 1980. The plant is assumed to have a 30-year lifetime of 117,500 operating hours and to operate 6,000 hours in the first year. Fly ash removal of 99.2% by electrostatic precipitators (ESP) upstream of the FGD system is not included in FGD costs. The base case fuel is a 3.5% sulfur, 16% ash, 5,830 kcal/kg high heat rate bituminous coal. For this fuel and all other solid fuels it is assumed that 95% of the sulfur and 80% of the ash are emitted in the flue gas. For oil all of the sulfur in the fuel is assumed emitted in the flue gas.

The FGD systems are assumed to be installed downstream from the ESP units. For the wet systems the flue gas is supplied from a common plenum to four parallel trains of SO_x removal equipment including booster

FD fans and reheat provisions. Presaturators to cool the gas from 149° to 53°C and mist eliminators to reduce liquid entrainment to 0.1% are provided. Indirect steam reheat (or direct-fired for oil-fired units used in the FGD process) is provided to reheat the gas entering the stack plenum to 79°C. The dry adsorption process is similar except two trains are used and reheat is not required. Costs for chloride removal facilities are included for the regenerable processes, however, costs for chloride disposal facilities are excluded. The FGD system consists of the common plenum and all equipment downstream to the stack plenum, including all raw material and effluent processing equipment and land requirements. Removal efficiencies are assumed to be 90% of the SO_2, 50% of the SO_3, 95% of the chloride, and 75% of the remaining fly ash in the flue gas. Specific conditions for the FGD processes are shown in Table S-1.

The economic premises are based on U.S. regulated utility economics and financing. The costs estimated consist of capital costs for construction of the FGD system and annual revenue requirements for the first-year operation. All costs are based on Midwestern U.S. costs using mid-1979 as the basis of capital costs and mid-1980 as the basis for annual revenue requirements. Capital costs consist of all direct and indirect costs for equipment, land, materials, labor, fees, services, and other construction costs required to install the FGD system. Annual revenue requirements, based on a first-year, 6000-hour operation, consist of all raw material, labor, utility, and other conversion costs and indirect costs such as capital charges, taxes, and overheads. Byproduct sales for processes producing elemental sulfur, H_2SO_4, gypsum and sodium sulfate are included as credits. For the gypsum-producing processes, however, costs for disposal of gypsum may be obtained where necessary by substituting a disposal charge for stacking or landfill of the gypsum in place of the credit. These costs are projected to range between $4 and $9 per ton of dry solids, depending on site-specific conditions.

Case Variations

Case variations, in which design assumptions are varied to determine effect on costs, are also evaluated. Except for the seawater process, 0.8%, 1.4%, and 2.0% sulfur bituminous coal; 0.5% sulfur lignite; and 2.5% sulfur oil fuels are included. The seawater process is not evaluated for the 2.0% and 3.5% sulfur coals because those coals would require additional seawater in addition to condenser water. Other case variations consist of 200-, 700-, and 1000-MW power plant sizes for the limestone sludge process; reheat to 53°C for the seawater process; and a sulfur production case for the Wellman-Lord process.

In addition to the case variations reported it is possible to scale other power plant size and fuel variaions using relative gas and product rates and scaling factors. Data and procedures for scaling are provided in the report.

TABLE S-1. SUMMARY - BASE-CASE FGD DESIGN ASSUMPTIONS

Design factor	FGD processes: Limestone sludge	Lime sludge	Double-alkali sludge	Seawater[a]
SO_2 removal device	mobile bed	mobile bed	tray tower	packed bed
Stoichiometry, mol/mol SO_2 removal	1.4	1.05	1.0	-
Design gas velocity, m/sec (SO_2 removal device)	3.8	3.8	2.1	1.8
L/G, liters/m^3				
Presaturator	0.6	0.5	0.5	0.5
Chloride scrubber	-	-	-	-
SO_2 removal device	6.7	7.4	0.9	8.0
Design pressure drop, kPascals (SO_2 removal device)	2.14	2.14	1.25	1.05
Reheat temperature, °C	79	79	79	79
Byproduct/waste management	clay-lined disposal pond	clay-lined disposal pond	clay-lined disposal pond	returned to sea
Probable accuracy range factors for capital investment estimates	0.85 to 1.20	0.85 to 1.20	0.80 to 1.30	0.70 to 1.50
Case variations[b]	5 fuel alternatives 200 MW 500 MW 1000 MW	5 fuel variations	5 fuel variations	3 fuel variations low reheat

(continued)

TABLE S-1 (continued)

Design factor	FGD processes				
	Lime gypsum	Jet-bubbling limestone	Magnesium oxide	Sodium sulfite	Carbon adsorption
SO_2 removal device	ROTOPART gas scrubber-separator	jet-bubbling reactor	spray grid tower	valve tray	moving bed
Stoichiometry, mol/mol SO_2 removal	1.01	1.0	1.05	1.0	7.5 kg S/100 kg char
Design gas velocity, m/sec (SO_2 removal device)	12.2	proprietary	3.8	-	-
L/G, liters/m^3					
Presaturator	-	proprietary	-	-	-
Chloride scrubber	-	-	0.5	1.6	-
SO_2 removal device	-	proprietary	3.0	-	-
Design pressure drop, kPascals (SO_2 removal device)	2.44	3.94	3.24	2.64	0.5 first stage 0.3 second stage
Reheat temperature, °C	79	79	79	79	none
Byproduct/waste management (sales credit, \$/short ton)	gypsum 3.00/ton	gypsum 3.00/ton	sulfuric acid 25.00/ton 100% acid	sulfuric acid 25.00/ton 100% acid	sulfur 40.00/ short ton
Probable accuracy range factors for capital investment estimates	0.70 to 1.50	0.70 to 1.50	0.80 to 1.30	0.80 to 1.30	0.70 to 1.50
Case variations[b]	5 fuel variations	5 fuel variations	5 fuel variations	5 fuel variations sulfur production	5 fuel variations

Basis for all base-case processes:
99.2% fly ash removed in ESP and disposed of separately, 95% of S in coal emitted in flue gas, 90% FGD SO_x removal, 4 absorber trains with reheat to 79°C for all wet processes, 2 adsorber trains and no reheat for the carbon adsorption process, 3.5% S (5,830 kcal/kg) coal.

a. Seawater base-case fuel is 1.4% S coal.

b. Case variation fuels, 0.8% S (5,280 kcal/kg), 1.4% S (7,000 kcal/kg), and 2.0% S (6,110 kcal/kg) bituminous coal; 0.5% S (4,390 kcal/kg) lignite and 2.5% S (10,490 kcal/kg) oil. 3.5% S and 2.0% S coal not used in seawater process.

RESULTS

Process and economic evaluation results are shown in Table S-2. The accuracy ranges for the base case capital investment and annual revenue requirements are shown in Figures S-1 and S-2. All capital investments are in mid-1979 U.S. dollars; all revenue requirements are in mid-1980 U.S. dollars.

ELEMENTS IN SELECTING AN FGD SYSTEM

Decisions on selection of an FGD process for a particular situation must consider four site-specific conditions: raw material costs, the desired end product, performance requirements, and plant site conditions. By development of a chart-based matrix which defines and relates FGD process characteristics, the site-specific conditions can be compared with the FGD process characteristics to eliminate impracticable processes.

After elimination of impracticable processes, the remaining processes can be rated by a similar procedure to identify their relative feasibility. The system applies ratings to the FGD system operability, process requirements, and costs. These ratings are then compared with the specific site requirements to further define the more practical processes. Detailed procedures and charts for using the procedure are included in the report.

TABLE S-2. SUMMARIZED RESULTS - ENERGY, LAND, CAPITAL INVESTMENT, AND ANNUAL REVENUE REQUIREMENTS

Process	Energy consumption, % of input energy	Land, hectares	Capital investment		Annual revenue requirements	
			M$	$/kW	M$	Mills/kWh
Limestone Sludge						
0.8% S in coal	3.3	42	40.0	80	11.2	3.7
1.4% S in coal	3.2	56	41.6	83	11.5	3.9
2.0% S in coal	3.2	78	45.5	91	12.6	4.2
3.5% S in coal	3.3	127	53.1	106	14.6	4.9
0.5% S in lignite	3.3	34	39.0	78	10.9	3.7
2.5% S in oil	2.7	70	40.6	81	11.4	3.8
200 MW, 3.5% S in coal	3.4	64	26.3	132	7.0	5.9
700 MW, 3.5% S in coal	3.3	163	71.0	101	19.7	4.7
1000 MW, 3.5% S in coal	3.3	213	93.9	94	26.4	4.4
Lime Sludge						
0.8% S in coal	3.3	35	37.8	76	11.1	3.7
1.4% S in coal	3.1	47	38.9	78	11.5	3.8
2.0% S in coal	3.2	66	42.0	84	12.6	4.2
3.5% S in coal	3.2	107	47.7	96	15.0	5.0
0.5% S in lignite	3.3	28	37.2	74	10.8	3.6
2.5% S in oil	2.5	57	37.3	75	11.4	3.8
Double-Alkali Sludge						
0.8% S in coal	2.5	38	40.5	81	11.2	3.7
1.4% S in coal	2.4	49	42.2	84	11.8	3.9
2.0% S in coal	2.5	67	46.0	92	13.1	4.4
3.5% S in coal	2.5	104	53.2	107	16.0	5.3
0.5% S in lignite	2.5	36	39.6	79	10.8	3.6
2.5% S in oil	1.9	53	40.7	81	11.9	4.0
Seawater						
0.8% S in coal	4.2	2	29.6	59	8.7	2.9
1.4% S in coal	4.2	2	30.0	60	8.7	2.9
0.5% S in lignite	4.2	2	29.1	58	8.5	2.8
2.5% S in oil	3.5	2	27.9	56	8.6	2.9
1.4% S in coal, low reheat	2.8	2	28.6	57	7.8	2.6
Lime Gypsum						
0.8% S in coal	2.9	5	35.5	71	9.8	3.3
1.4% S in coal	2.9	5	36.5	73	10.3	3.4
2.0% S in coal	3.2	5	39.2	78	11.4	3.8
3.5% S in coal	3.7	5	44.0	88	13.7	4.6
0.5% S in lignite	2.9	5	34.9	70	9.6	3.2
2.5% S in oil	2.5	5	34.8	70	10.3	3.5
Jet-Bubbling Limestone						
0.8% S in coal	3.4	5	42.0	84	10.9	3.7
1.4% S in coal	3.3	5	42.0	84	10.9	3.6
2.0% S in coal	3.3	5	43.8	88	11.4	3.8
3.5% S in coal	3.4	5	47.0	94	12.2	4.1
0.5% S in lignite	3.3	5	42.1	84	11.0	3.7
2.5% S in oil	2.6	5	38.5	77	10.2	3.4

(continued)

TABLE S-2 (continued)

Process	Energy consumption, % of input energy	Land, hectares	Capital investment M$	Capital investment $/kW	Annual revenue requirements M$	Annual revenue requirements Mills/kWh
Magnesium Oxide						
0.8% S in coal	3.9	3	48.9	98	12.9	4.3
1.4% S in coal	4.1	3	52.0	104	13.7	4.6
2.0% S in coal	4.8	3	58.1	116	15.1	5.0
3.5% S in coal	6.3	3	68.4	137	17.5	5.9
0.5% S in lignite	3.8	3	47.1	94	12.6	4.2
2.5% S in oil	3.7	3	44.6	89	12.0	4.0
Sodium Sulfite						
0.8% S in coal	4.1	3	46.8	94	12.2	4.1
1.4% S in coal	4.6	3	50.3	101	13.1	4.4
2.0% S in coal	5.7	3	56.9	114	14.8	4.9
3.5% S in coal	8.1	3	68.7	137	17.9	6.0
0.5% S in lignite	3.9	3	44.8	90	11.8	3.9
2.5% S in oil	4.5	3	44.2	88	11.8	3.9
3.5% S in coal, sulfur production	9.9	3	71.3	143	21.0	7.0
Carbon Adsorption						
0.8% S in coal	0.6	5	51.2	102	13.9	4.6
1.4% S in coal	0.8	5	54.2	108	15.8	5.3
2.0% S in coal	1.0	5	60.8	122	20.0	6.7
3.5% S in coal	1.7	5	73.5	147	28.5	9.5
0.5% S in lignite	0.5	5	49.5	99	12.8	4.3
2.5% S in oil	0.9	5	53.7	107	17.5	5.9

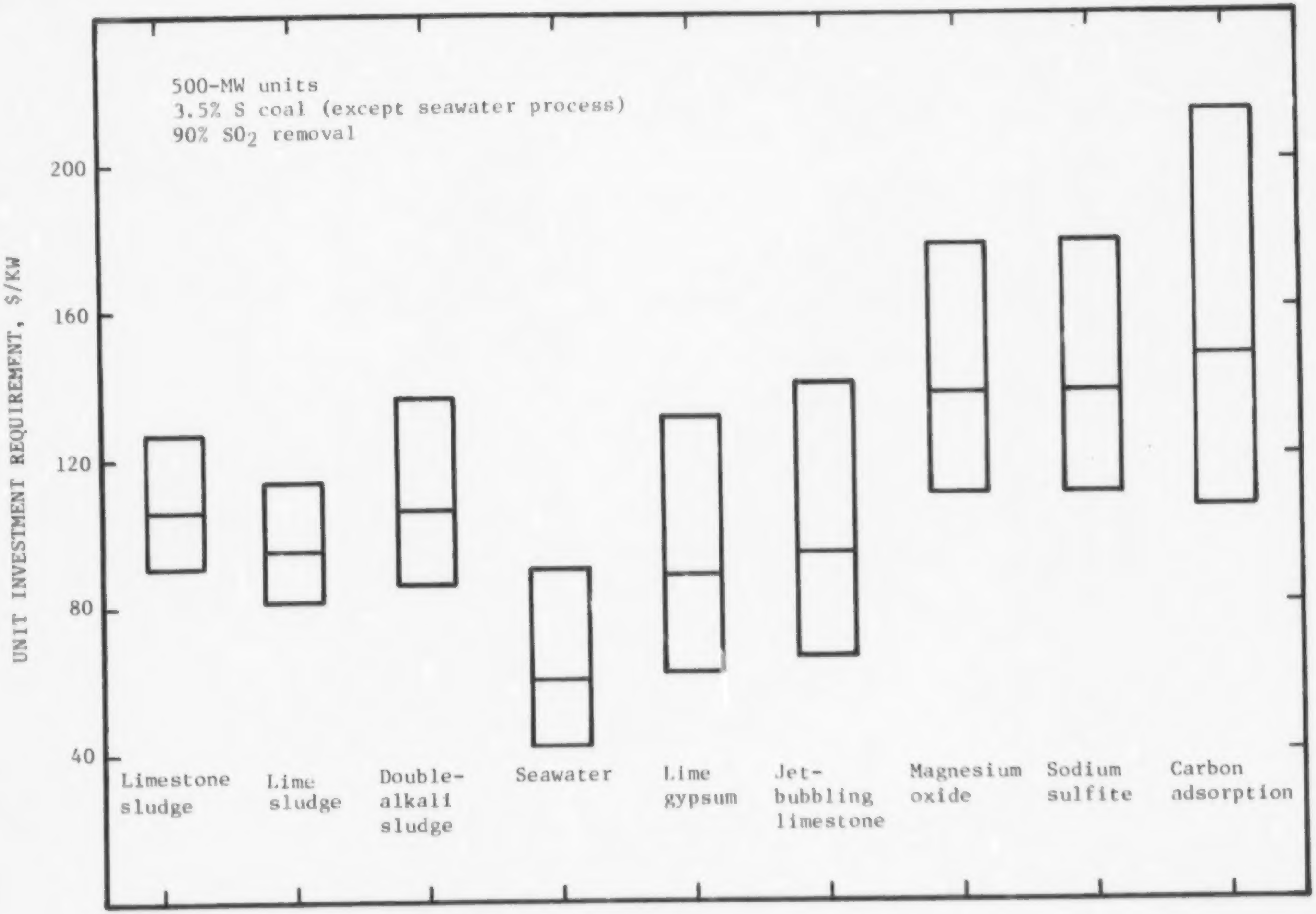


Figure S-1. Base-case unit investment range for alternate processes.

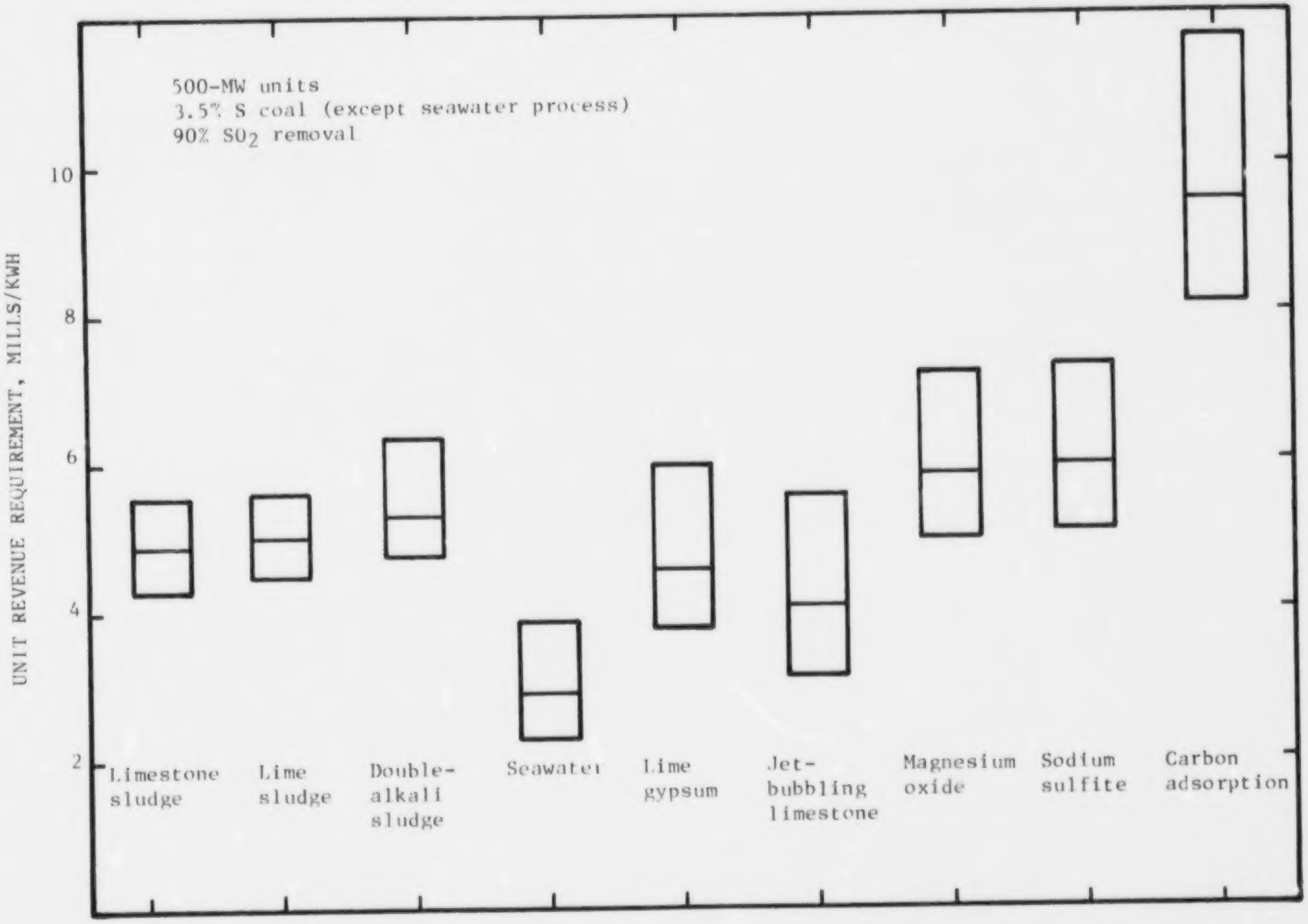


Figure S-2. Base-case unit revenue requirement range for alternate processes.

NATO-CCMS

FLUE GAS DESULFURIZATION PILOT STUDY

PHASE II - APPLICABILITY STUDY

INTRODUCTION AND DISCUSSION

The Phase I report (1) prepared for the North Atlantic Treaty Organization Committee on the Challenges of Modern Society (NATO-CCMS) Flue Gas Desulfurization (FGD) Study Group describes 12 FGD processes using data derived from a number of sources. During the April 1978 meeting of the NATO-CCMS delegates in Norway the 12 processes were reviewed and 9 were selected for further economic evaluation as Phase II of the NATO-CCMS study.

This Phase II study was prepared jointly by the U.S. Tennessee Valley Authority and PEDCo Environmental, Inc. It consists of economic analyses of the nine FGD processes for a variety of fuels and power plant sizes and a selection matrix procedure for selection of an FGD process based on plant site characteristics and technical requirements. The economic evaluations can be used to identify the most economical processes. A limited technical and state-of-development review of each process is provided as a further aid in assessing accuracies and applicability of the data. The selection matrix provides a method of narrowing the number of FGD processes to be considered for a particular application by a process of elimination.

The technical and economic evaluations are based on cost analysis procedures developed by TVA for a number of FGD economic evaluations conducted during the past several years. The evaluations are made using consistent design and economic premises which permit equitable comparisons of different processes. The design premises define a representative U.S. electric utility 500-MW power plant. Six fuels--bituminous coals, lignite, and oil--are evaluated. The economic premises are based on U.S. regulated-utility economics and are calculated in U.S. dollars. The premises permit cost projections to other power plant sizes and to other cost-base years by use of scaling factors and economic indexes.

The selection matrix system for identification of feasible FGD processes provides a procedure which relates specific site conditions and requirements to the capabilities and characteristics of each FGD process. Impracticable processes are excluded from consideration and the remaining processes are weighed. The system is an initial-selection procedure which allows FGD process selection efforts to be narrowed, thus focusing attention on the most promising processes for a particular application.

It must be emphasized that the data for this report are derived on a different base than the data in the Phase I report (1,2). Therefore, there is no overall relationship between the data in the Phase I report and this report and comparisons must be made with extreme caution. The differences result from both updated technology and updated design and economic premises.

It is also very important when studying the cost data in this report that the underlying technical and economic assumptions are fully understood. The economic bases in particular relate only to present U.S. conditions. The report only derives comparative costs and its value does not lie as much in the absolute values as in illustrating the relativities between the FGD processes and the economic significance of elements within each process.

The economic premises should be carefully noted. While it would undoubtedly have been helpful to the participating countries to have utilized premises more appropriate to West Europe, it was not possible to do so within the scope of this report. It is possible that if this were to be done it would show significant changes in relativities. To obtain the results various simplifying technical assumptions have unavoidably had to be made. Each FGD process involves the disposal of some solid or liquid waste products to the surrounding environment. Liquid effluents can include purged reagents or, more commonly, soluble chlorides derived from the coal. Solid wastes contain some soluble materials which can leach into the ground. With the processes that produce gypsum, some or all of the byproduct may be salable but some may need to be discarded as waste, depending upon market conditions. With the processes that produce sulfuric acid, elemental sulfur, or sodium sulfate it must be presumed that all the output is sold.

An aspect which also deserves mention is that some of the FGD processes studied in this report are linked to a single contracting company or group whereas others are offered by several contractors. In the latter case a variety of equipment designs may be available with differing investment and revenue requirements.

All of the matters mentioned above have an effect upon the overall economics of the FGD installation and in certain circumstances the effect may completely alter the relativities of process costs. The importance of these factors must be borne in mind when studying the cost comparisons. Reference may usefully be made to Section 5 of the NATO-CCMS Summary Report, No. 95 (2).

Unless the qualifications outlined in the preceding paragraphs are taken fully into consideration there is a risk that conclusions may be drawn that will not correspond with the real circumstances. The cost data in this report represent a "coarse sieve." They can be valuable in delineating the major cost areas of the FGD processes and in directing attention to areas where improvements may be sought.

The primary objective of this study is to evaluate FGD processes in terms of their applicability and economics. As such, the FGD processes are considered as an entity, separate from other control procedures which may also be necessary in the overall power plant operation to control emissions and effluents. Fly ash control, for example, is not included in these evaluations although it is a necessary adjunct to power plant operations with many fuels. Other wastes such as nitrogen oxides, bottom ash, blowdown, waste water, and storage area runoff may also require control. An integrated waste-control system incorporating all necessary aspects of waste control for a particulate site may offer economic advantages. In evaluating the FGD processes in this study for a particulate site, therefore, it may be advantageous to consider control of nitrogen oxides and fine particulates as well as sulfur, and the ultimate disposal of collected waste products in an integrated emission-effluent control system.

Many important items have not been studied in great detail in Phases I and II of this study. New FGD techniques are being developed, designed primarily to overcome technical and economic imperfections of the present generation of FGD processes. Spray-drying techniques are examples of these developments. Existing systems are being improved to decrease energy consumption. Other important developments are the application of gas - gas reheat systems, the simplification of scrubbers, the increase of the reactivity of the absorbent using minor amounts of additives, and improved mist eliminator designs.

For economic considerations, the expected lifetime of the installation is an important variable. FGD systems have now been in operation for several years and it could be of great value to evaluate maintenance records as a means of determining expected lifetimes.

A very important problem is the use or disposal of the sulfur-containing byproduct in an environmentally acceptable way. Especially, disposal of sludge and possibly gypsum can create problems. Leaching of soluble compounds can be a potential danger to the quality of groundwater. In this context it is very important to develop potential applications for sludge and to find new applications for gypsum.

It is hardly possible to operate wet FGD systems without a waste water purge, either from a prescrubber or from the main scrubbing loop. This waste water can introduce the necessity of a waste water treatment.

In addition to FGD other techniques to decrease SO_2 emissions are in use or in the development stage. Fuel desulfurization, such as hydrodesulfurization of fuel oils and coal cleaning, fluidized-bed combustion of fuel oils and coal, and coal gasification, is being investigated.

The NATO-CCMS Study Group has noted the continuing improvement in existing FGD systems, the development of new FGD systems, the growing concern about secondary pollution by solid and liquid wastes, and the use and development of other techniques to decrease SO_2 emission to the atmosphere, such as fluidized-bed combustion and spray drying/absorption processes. Because of these developments, consideration of processes for meeting SO_2 emission regulations should not be limited to those processes included within this study. With the growing international interest in SO_2 control, the study group is strongly of the opinion that a continuing examination and review of existing and newly developed FGD systems and the secondary pollution problems related to these systems should be undertaken within the NATO-CCMS forum. In a later phase other desulfurization techniques can be evaluated. Having developed already a strong working relationship and understanding, the present NATO-CCMS Study Group should be fully capable of this task.

PROCESSES EVALUATED

LIMESTONE SCRUBBING WITH UNTREATED SLUDGE WASTE DISPOSAL

The process evaluated is a generic design based on the large body of information available on limestone scrubbing. TVA also has a considerable amount of internal data from the EPA-sponsored Shawnee test program and the 550-MW Widows Creek power plant scrubbing unit. A computer program has been developed for calculating limestone and lime scrubbing economics which is used in economic evaluations of these scrubbing processes (3). TVA has published a detailed evaluation of these processes (4). An updated definitive economic and energy-use evaluation has also been published (5). Because of the large body of technical, operational, and economic data on the limestone process, actual investments could vary within a range of 0.85 to 1.20 times the projected capital investment results.

LIME SCRUBBING WITH UNTREATED SLUDGE WASTE DISPOSAL

The process evaluated is a generic design based on the extensive information available for this process, including considerable data from the Shawnee test program. A computer program is used to conduct economic evaluations of lime scrubbing processes. Except for absorbent feed preparation and details of operating conditions and stoichiometry the process is similar to the limestone sludge process. In addition to a previous study of this process (4), an updated definitive economic and energy-use evaluation of this process has been published (6). Because of the large amount of information on the lime process, actual investments could vary within a range of 0.85 to 1.20 times the projected capital investment results.

DOUBLE-ALKALI SCRUBBING WITH UNTREATED SLUDGE WASTE DISPOSAL

The process evaluated is a generic design based on a substantial body of industry information and experience with components of the system. Large-scale application of the entire process in utility use is only in the construction stage, however. A definitive economic evaluation of this process prepared by TVA has been published (5). Because of the large amount of information available on process components, although operational information is limited, actual investments could vary within a range of 0.80 to 1.30 times the projected capital investment results.

SEAWATER SCRUBBING WITH OCEAN DISPOSAL OF OXIDIZED WASTE

The process evaluated is based on the Flakt-Hydro process using information obtained from the Foundation of Scientific and Industrial Research at the University of Trondheim, Norway, and A/S Norsk Viftefabrikk, Oslo, Norway. The process is in operation on three industrial boilers of A/S Norsk Hydro, Porsgrunn, Norway (with a total capacity equivalent to a 50-MW power plant) using glass-fiber-reinforced polyester scrubbers and alkali neutralization of the waste stream. The process evaluated in this study uses neoprene-lined steel scrubbers and condenser cooling water for absorption and neutralization. In addition, only the low-sulfur coals and oil are evaluated because it is assumed that only condenser water is used for scrubbing. Higher sulfur coals would require additional seawater or alkali addition. Actual investments could vary within a range of 0.70 to 1.50 times the projected capital investment results.

LIME SCRUBBING WITH OXIDATION AND DEWATERED GYPSUM WASTE DISPOSAL

The process evaluated is based on the Saarberg-Holter process using additional data supplied by Davy Powergas, Inc., Houston, Texas. The process was developed by Saarberg-Holter Umwelttechnik GmbH, Saarbrucken, West Germany. Although the extent of developmental work on this process is somewhat limited in comparison to other processes it has been under development and evaluation for several years and is currently being installed both on operational utility boilers and on industrial processes. Davy Powergas is the U.S. licensee for the process. Actual investments could vary within a range of 0.70 to 1.50 times the projected capital investment results.

JET-BUBBLING LIMESTONE SCRUBBING WITH DEWATERED GYPSUM DISPOSAL

The process evaluated is based on the Chiyoda Thoroughbred 121 process, an evolution of the Chiyoda Thoroughbred 101 process described in the NATO-CCMS Phase I study. The amount of developmental work on this process is also not as extensive as for other processes. The design is based on information supplied by Chiyoda International Corporation, Seattle, Washington. The process is being evaluated on a 23-MW prototype unit at the Scholz Steam Plant of Gulf Power Company in Sneads, Florida. Actual investments could vary within a range of 0.70 to 1.50 times the projected capital investment results.

MAGNESIUM OXIDE SCRUBBING WITH SULFURIC ACID PRODUCTION

The process evaluated is based on a generic design representing general industry information. The magnesium oxide process in the Phase I study is based on a 1975 TVA evaluation (4). Since that time additional operating experience has been gained with developmental and prototype units. In particular, modifications have been made in the dewatering and drying steps and additional heat recovery capabilities have been incorporated. An updated definitive economic and energy-use evaluation of the magnesium oxide process has been published (6). This information has been incorporated into the current study. Actual investments could vary within a range of 0.80 to 1.30 times the projected capital investment results.

SODIUM SULFITE SCRUBBING WITH SULFURIC ACID AND SULFUR PRODUCTION

The process evaluated is based on Wellman-Lord scrubbing process with regeneration of SO_2 and production of sulfuric acid. An alternative process based on Wellman-Lord/Allied Chemical technology for producing elemental sulfur with natural gas reduction is also included. A definitive economic evaluation of the Wellman-Lord/Allied Chemical process was made by TVA in 1975 (4). This evaluation is the basis of the Phase I study. A considerable amount of additional information on this process based on additional development and prototype and commercial operating experience has been obtained since the 1975 evaluation, and is incorporated into this evaluation. In addition to published information, data were supplied by Davy Powergas, Inc., Lakeland, Florida, the Allied Chemical Company, New York, and the Northern Indiana Public Service Company, Gary, Indiana. The major changes are the use of double-effect instead of single-effect evaporators, elimination of the antioxidant, use of common wall scrubber units, sulfate control by high temperature crystallization, smaller process tanks, additional credit for condensate, and carbon-steel sulfur storage tanks. A definitive economic evaluation of this process incorporating these changes will be published in 1980. Actual investments could vary within a range of 0.80 to 1.30 times the projected capital investment results.

DRY CARBON ADSORPTION WITH SULFUR PRODUCTION

The process evaluated is based on the Bergbau Forschung - Foster Wheeler process. The design is based on published information and additional information provided by Foster Wheeler Corporation, Livingston, New Jersey. The SO_x removal process was developed by Bergbau Forschung GmbH, Essen, West Germany, and has had extensive developmental and operational investigation for several years. A Foster Wheeler RESOX® process using anthracite is used to reduce the SO_2 to sulfur.

Although a considerable body of design and operating data is available, equipment cost information for this study is limited. Because of this, actual investments could vary within a range of 0.70 to 1.50 times the projected capital investment results.

PREMISES FOR ECONOMIC EVALUATIONS

The premises and assumptions for the economic evaluations have been used by TVA for a number of FGD economic studies. These premises were reviewed at the April 1978 NATO-CCMS meeting. The base-case premises are designed to represent a typical U.S. power plant. Case variations in which fuel type or sulfur content is varied are included to determine the sensitivity of costs to these variations in conditions.

DESIGN PREMISES

The design premises define all major power-plant, fuel, emissions, and SO_x removal requirements necessary to design an FGD system. These general premises are discussed below. Additional premises specific to the individual processes are included with the discussion of each process in the appendixes.

Power Plant

A new, balanced-draft, horizontal, frontal-fired boiler design is used for the coal-fired cases. A tangential-fired boiler is used for the oil-fired case. The base case is a 500-MW unit. Case variations of 200-, 700-, and 1000-MW sizes are included for the limestone sludge process. The power plant is assumed to have a 2,268 kcal/kWh (9,000 Btu/kWh) heat rate and an operating lifetime of 117,500 hours over a 30-year period. A 6000 hr/yr operating schedule is used for the annual revenue requirements analysis.

Fuel

Six fuel variations are used--four bituminous coals of different sulfur content, lignite, and oil. A 3.5% sulfur coal is used for the base case of all processes except the seawater process. For this process the 1.4% sulfur coal is used as the base case. Table 1 shows the composition, high heating value (HHV), and feed rates of the various fuels.

Flue Gas Composition

Flue gas compositions for the coal and lignite fuels are based on combustion of pulverized fuel and a total air rate of 133% of the stoichiometric requirements. This includes 20% excess air to the boiler and 13% air inleakage at the air preheater. Flue gas composition for the oil fuel is based on a total air rate of 115% of the stoichiometric require-

TABLE 1. PROJECTED AS-FIRED FUEL COMPOSITION FOR BASE CASE AND ALTERNATE FUELS

	3.5% sulfur coal[a] (base case) 5,830 kcal/kg HHV, as fired			0.8% sulfur coal[a] 5,280 kcal/kg HHV, as fired			1.4% sulfur coal[a] 7,000 kcal/kg HHV, as fired		
Component	Wt %	Kg/hr	Lb/hr	Wt %	Kg/hr	Lb/hr	Wt %	Kg/hr	Lb/hr
C	57.56	111,900	246,800	54.60	117,400	258,700	70.70	114,600	252,600
H	4.14	8,000	17,700	4.05	8,700	19,200	4.59	7,400	16,400
O	7.00	13,600	30,000	12.42	26,700	58,800	7.51	12,200	26,800
N	1.29	2,500	5,500	1.12	2,400	5,300	1.30	2,100	4,600
S	3.12	6,100	13,400	0.66	1,400	3,100	1.30	2,100	4,600
Cl	0.15	300	600	0.15	300	700	0.30	500	1,100
Ash	16.00	31,100	68,600	10.00	21,500	47,400	7.00	11,300	25,000
H_2O	10.74	20,900	46,000	17.00	36,500	80,500	7.30	11,800	26,100
Total[b]	100.00	194,400	428,600	100.00	214,900	473,700	100.00	162,000	357,200

	2.0% sulfur coal[a] 6,110 kcal/kg HHV, as fired			0.5% sulfur lignite[a] 4,390 kcal/kg HHV, as fired			2.5% sulfur No. 6 oil 10,480 kcal/kg HHV, as fired		
Component	Wt %	Kg/hr	Lb/hr	Wt %	Kg/hr	Lb/hr	Wt %	Kg/hr	Lb/hr
C	61.35	113,900	251,000	41.5	107,200	236,400	83.66	90,900	200,400
H	4.14	7,700	16,900	6.8	17,600	38,700	11.46	12,500	27,500
O	7.00	13,000	28,600	30.7	79,300	174,900	1.25	1,400	3,000
N	1.31	2,400	5,400	0.5	1,300	2,800	0.63	700	1,500
S	1.80	3,300	7,400	0.4	1,000	2,300	2.50	2,700	6,000
Cl	0.40	700	1,600	0.1	300	600	-	-	-
Ash	16.00	29,700	65,500	5.0	12,900	28,500	0.10	100	200
H_2O	8.00	14,800	32,700	15.0	38,700	85,400	Sediment: 0.40	400	1,000
Total[b]	100.00	185,500	409,100	100.0	258,300	569,600	100.00	108,700	239,600

a. Dry basis.
b. Feed to boiler. Coals and lignite are pulverized.

ments, including 5% excess air to the boiler and 10% air inleakage at the air preheater. An ambient air temperature of 27°C (80°F) and a 60% relative humidity is used for all cases.

SO_x in the flue gas is assumed to consist of 99% SO_2 and 1% SO_3. For the coal- and lignite-fired cases 80% of the ash and 95% of the sulfur in the fuel is assumed to be emitted in the flue gas as fly ash and SO_x. For the oil-fired case 100% of the ash and sulfur in the oil is assumed to be emitted in the flue gas. In addition 0.4% of the oil to the boiler is assumed to be emitted as particulate matter. For the coal- and lignite-fired cases the flue gas is assumed to contain 0.06% by volume NO_x, calculated as NO. For the oil-fired case the flue gas is assumed to contain 0.02% by volume NO_x. Flue gas compositions and rates based on these assumptions are shown for each fuel in Table 2.

Removal Efficiencies

For all coal- and lignite-fired cases 99.2% of the fly ash is assumed removed in ESP units. ESP units are not used for the oil-fired case. The presaturators and scrubbers are assumed to remove 90% of the SO_2, 50% of the SO_3, 95% of the chloride, and 75% of the remaining fly ash in the flue gas. (In the coal- and lignite-fired cases the fly ash removed by the presaturator and scrubbers is the residual ash that is not removed by the ESP units.)

FGD Systems

The FGD system is installed downstream from the ESP units (or air preheaters in the oil-fired case). Flue gas from the power plant is routed through a single plenum which distributes the gas to parallel FGD equipment trains. The plenum is equipped with flow controls to shut down individual FGD trains but it is not provided with bypass capabilities.

Four trains of FGD equipment are used for the wet processes and two trains are used for the dry, carbon-adsorption process. For the case variations 2, 6, and 8 trains are used for 200-, 700-, and 1000-MW power plant sizes. Each train is equipped with a forced-draft (FD) booster fan (in respect to the FGD facilities) to compensate for the additional pressure drop in the FGD system. Presaturators and mist eliminators are provided for wet-process absorbers. The flue gas is assumed to enter the presaturator at 149°C (300°F) and enter the absorber at 53°C (127°F). The mist eliminator is assumed to reduce the entrained moisture content of the flue gas leaving the absorber to 0.1%. For wet processes reheat is provided to heat the flue gas to 79°C (175°F) before it is exhausted to the stack plenum. It is recognized, however, that requirements for reheat for plume buoyancy, corrosion control, and opacity are site specific and may vary.

The FGD systems are assumed to include the plenum which receives the flue gas from the ESP units or air preheaters and all FGD equipment downstream to the stack plenum. All equipment and facilities necessary to operate the system, including raw material processing and waste

TABLE 2. ESTIMATED FLUE GAS COMPOSITIONS

FOR POWER UNITS WITHOUT EMISSION CONTROL FACILITIES

	Volume %					
	3.5% S in coal (Base case)	0.8% S in coal	1.4% S in coal	2.0% S in coal	0.5% S in lignite	2.5% S in oil
Component						
N_2	73.76	72.41	74.43	74.18	68.66	73.60
O_2	4.83	4.75	4.88	4.86	4.50	2.54
CO_2	12.31	12.59	12.73	12.59	11.22	11.96
SO_2	0.24	0.05	0.08	0.13	0.04	0.13
SO_3	0.0024	0.0005	0.0008	0.0013	0.0004	0.0013
NO	0.06	0.06	0.06	0.06	0.06	0.02
HCl	0.01	0.01	0.02	0.03	0.009	-
H_2O	8.79	10.13	7.80	8.15	15.51	11.75
Flow Rate						
m^3/min at 0^oC	28,280	28,980	28,000	28,130	29,720	23,550
ft^3/min at 0^oC	998,700	1,023,300	988,900	993,500	1,049,700	831,500
Fly Ash Loading						
g/m^3 - wet	14.67	9.88	5.40	14.07	5.79	0.07
gr/ft^3 - wet	6.41	4.32	2.36	6.15	2.53	0.03

disposal or treatment, are included. Wastes, excluding small purge streams, are assumed to be disposed of on land one mile from the facility.

ECONOMIC PREMISES

The economic premises are divided into capital investment premises for installation of the system and annual revenue requirement premises, for its operation over the life of the power plant. The premises are further divided into sections to facilitate calculation and to establish cost areas for comparison and analysis. The estimates are based on generalized flow diagrams, material balances, equipment lists, plot plans, and various layouts of electrical equipment, piping, and instrumentation, along with other design and operating information. Capital cost information for process items is obtained from engineering-contracting, processing, and equipment companies; TVA purchasing and construction data; and authoritative publications on costs and estimating. Minor equipment costs are based on literature sources or derived as a function of major equipment costs. Revenue requirements are based on current U.S. labor and supervisory rates, purchased power costs, costs derived from literature sources, and current industrial practice. All costs are in U.S. dollars and are based on costs in the Midwestern United States.

The premises are designed to represent projects in which design begins in mid-1977 and construction is completed in mid-1980, followed by a mid-1980 startup. Capital costs are assumed 50% expended in mid-1979. Therefore, projected capital costs are assumed to correspond to mid-1979 and revenue requirements are projected to 1980. Scaling to other time periods can use mid-1979 as the basis for capital costs and mid-1980 as the basis for revenue requirements.

The premises are based on regulated utility economics which allow the power company to earn a specified return on investment. The FGD system cost is combined with the total power plant investment and, therefore, increases the rate base upon which the utility return on investment is based. Thus, a return on equity is included in any process evaluation under regulated economics. This cost of investment is added to the annual revenue requirements as part of capital charges. The capital structure is assumed to be 60% debt and 40% equity. Interest on bonds is assumed to be 10% and the return to stockholders 14%.

Capital Costs

Capital costs are categorized as direct investment, indirect investment, contingency, other capital charges, land costs, and working capital. Total fixed investment consists of the sum of direct and indirect capital investment and a contingency based on direct and indirect investment. Total depreciable investment consists of total fixed investment plus the other capital charges. Investment costs are projected from Chemical Engineering annual cost indexes (7) as shown in Table 3. The costs are based on construction of a proven design and an orderly construction program without delays or overruns caused by equipment, material, or labor shortages.

TABLE 3. COST INDEXES AND PROJECTIONS

Year	1974	1975	1976[a]	1977[a]	1978[a]	1979[a]	1980[a]	1981[a]
Plant	165.4	182.4	197.9	214.7	232.9	251.5	271.6	293.3
Material[b]	171.2	194.7	210.3	227.1	245.3	264.9	286.1	309.0
Labor[c]	163.3	168.6	183.8	200.3	218.3	237.9	259.3	282.6

a. Projections.
b. Same as index in Chemical Engineering for "equipment, machinery, supports."
c. Same as index in Chemical Engineering for "construction labor."

Direct Investment--

Direct capital costs include all costs, excluding land, for materials and labor to install the complete FGD system. Included are site preparation, excavation, buildings, storage facilities, landscaping, paving, and fencing. Process equipment consists of all major equipment and all equipment ancillary to the major equipment, such as piping, instrumentation, electrical equipment, and vehicles. Services, utilities, and miscellaneous costs involved in construction are estimated as 6% of the direct investment.

Indirect Investment--

Indirect investment costs consist of various contractor charges and fees and construction expenses. The following cost divisions and determinations are used.

Engineering design and supervision--ED&S cost is calculated as a function of the complexity of the system as determined by the number of major equipment items. The formula used is:

$$\text{ED\&S (in \$)} = (8900)(1.294)(\text{number of major process equipment pieces}) + (5\% \text{ to } 15\%)(\text{battery-limit investment})$$

A separate procedure, based on pond construction expense, is used to determine ED&S cost for the pond area.

$$\text{Pond ED\&S (in \$)} = (0.076)(\text{direct pond investment in M\$})^{0.67}(10^6)$$

The sum of these costs appears in indirect investment as ED&S expense.

Architect and engineering contractor expenses--A&E expense is calculated as 25% of the portion of ED&S associated with major equipment and battery-limit units. For cases involving disposal ponds, 10% of the ED&S associated with pond construction is estimated as A&E expense.

Construction expense--Construction expense is based on direct investment by the following equation:

$$\text{Construction expense (in \$)} = [0.25\ (a)^{0.83} + 0.13\ (b)^{0.83}](10^6)$$

where a = direct investment in M$ excluding pond investment costs

b = direct pond cost in M$

Contractor fees--A correlation between contractor fees and direct investment is used to estimate the cost of contractor fees.

$$\text{Contractor fees (in \$)} = (0.096)(\text{total direct investment in M\$})^{0.76}(10^6)$$

Contingency--Contingency is assumed to be 20% of the sum of direct and indirect investments.

Other Capital Charges--

Other capital charges consist of an allowance for startup and modifications and interest during construction. The allowance for startup and modifications is 10% of the total fixed investment excluding pond construction. Interest during construction is 12% of the total fixed investment. It is based on the simple interest which would be accumulated at 10% per year under the assumed construction and expenditure schedule, using the 60% debt-40% equity capital structure.

Land--

Total land requirements, including the waste disposal area for the life of the power plant, are assumed to be purchased at the beginning of the project. A land cost of $3500/acre is used.

Working Capital--

Working capital consists of money invested in raw materials and supplies, products in process, and finished products; cash retained for operating expenses; accounts receivable; accounts payable; and taxes payable. For these premises, working capital is assumed to be equivalent to the sum of 3 weeks of raw material costs, 7 weeks of direct costs, and 7 weeks of overhead costs.

Annual Revenue Requirements

Annual revenue requirements are based on a 6000 hr/yr operating schedule using the same operational profile and remaining life assumptions that were used for the power plant design premises. Costs are projected to 1980 dollars to represent a mid-1980 startup. The revenue requirements are divided into direct costs for raw materials and conversion and indirect costs for capital charges and overheads.

Direct Costs--

Projected direct costs for labor and electricity are shown in Table 4. Operating labor and supervision is based on the quantity, size, and complexity of the major process equipment. Labor for analyses

TABLE 4. PROJECTED MID-1980 UNIT COSTS FOR RAW MATERIALS, LABOR, AND UTILITIES

			$/unit
Raw Materials			
Limestone			7.72/metric ton 7.00/U.S. ton
Labor			
Operating labor			12.50/man-hr
Analyses			17.00/man-hr
Utilities			
Fuel oil (No. 6)			0.11/liter 0.40/gal
Steam (500 psig)			0.504/Mcal 2.00/MBtu
Process water			0.032/kliter 0.12/kgal
	200 MW	500 and 700 MW	1000 MW
Electricity	0.031/kWh	0.029/kWh	0.028/kWh

is based on the number of chemical analyses and physical tests needed for process control. Electrical requirements are determined from the installed horsepower of operating electrical equipment (excludes the horsepower of spare equipment). Each motor in operation is assumed to be operating at rated capacity although this results in higher power consumptions than would actually occur. Electricity costs are based on purchase from an independent source with full capital recovery provided.

Maintenance costs are based on a percentage of the direct investment costs excluding field disposal and pond construction. They are adjusted for the size and complexity of the process, considering operating experience with the processes or similar operations, and are assumed to be constant over the life of the plant, the increase in costs balanced by the decline in operating hours. Pond or field disposal maintenance is estimated as 3% of pond or field disposal construction cost. The following maintenance rates are applied to the direct investment excluding pond or field disposal construction cost.

Process	Projected maintenance rate, % of direct investment excluding pond or field disposal cost
Limestone sludge	8
Lime sludge	8
Double-alkali sludge	8
Seawater	6
Lime gypsum	6
Jet-bubbling limestone	6
Magnesium oxide	7
Sodium sulfite	6
Carbon adsorption	7

Indirect Costs--

Indirect costs consist of capital charges and overheads. Straight-line depreciation of 3.3% is used. Following U.S. Federal Energy Regulatory Commission (FERC) recommendations, an allowance for interim replacement is included. This allowance is increased to 0.7% from the usual average of about 0.35% because of the unknown life span of FGD systems. The insurance and property tax allowance, based on FERC practice, is 2.0% of the total depreciable capital investment. Cost of capital, based on the assumed capital structure and applied as an average charge, is 8.6% of the depreciable capital investment.

Methods of calculating overheads vary. The method used in these premises is based on information from several published sources. Plant overhead is assumed to be 50% of the total conversion cost excluding the cost of utilities. Utilities are excluded to avoid overcharging energy-intensive processes. Administrative overhead is assumed to be 10% of the operating labor and supervision cost.

Byproduct Sale

For processes in which a salable byproduct is produced, 10% of the total revenue is included in the overhead costs for marketing overhead and the total sales revenue is accounted for in the annual revenue requirements as a credit.

SCALING

The FGD case variation costs in this study are projected from the 500-MW base case using scale factors and ratios. With the exception of the seawater process the 3.5% sulfur fuel variation is used as the base case. For the seawater process the base-case fuel is the 1.4% sulfur coal because the 2.0% and 3.5% sulfur coals are not evaluated. The scaling procedure for projecting results of the base-case evaluation for other power plant sizes and fuel sulfur contents are described and illustrated below. Similar procedures may be used for projecting results for other applications not included in this study. Table 5 shows scaling data for power plant size and fuel variations.

Scaling Factors

Relative Gas and Product Rates--

Flue gas rates are functions of power plant size, fuel characteristics, and combustion conditions. The flow rate and composition of flue gas for each fuel type are shown in Table 2 of the premises. Using the 500-MW, 3.5% sulfur coal base case as the datum, relative gas rates for power plant size and fuel variations can be determined. As an example, the relative gas rate for the 500-MW oil-fired case based on the gas rates shown in Table 2 is calculated as (23,550 m^3/min)/(28,280 m^3/min) = 0.833. For cases in which the actual flue gas rates are not known, relative gas rates for other size variations can be determined by multiplying the relative gas rate for a specific plant by the size ratio and heat rate ratio of the plant in question to the known plant. For example, the relative gas rate for a 200-MW oil-fired power plant is

$$0.83 \left(\frac{200\ \text{MW}}{500\ \text{MW}}\right)\left(\frac{2319\ \text{kcal/kWh}}{2268\ \text{kcal/kWh}}\right) = 0.34$$

The product rate is a function of several variables: power plant size and heat rate, sulfur content of fuel, percentage of the sulfur in the fuel which is emitted as gaseous SO_2, and the removal efficiency of the FGD system. For the base case the product rate is

$$\begin{aligned}&(500{,}000\ \text{kW})(2{,}268\ \text{kcal/kWh})(1\ \text{kg fuel}/5{,}830\ \text{kcal})\ \times\\&\quad(0.0312\ \text{kg S/kg fuel})(0.95\ \text{kg S emitted/kg S})\ \times\\&\quad(0.90\ \text{kg S removed/kg S emitted}) = 5{,}188\ \text{kg/hr S removed}\end{aligned}$$

A similar calculation for the 500-MW oil-fired case (substituting 0.025 kg sulfur/kg fuel, 1.00 kg sulfur emitted/kg sulfur, and 10,480 kcal/kg)

TABLE 5. SCALING DATA FOR POWER PLANT SIZE AND FUEL VARIATIONS

Fuel Sulfur in fuel, % dry basis	Coal 3.5	Coal 3.5	Coal 3.5	Coal 3.5	Coal 0.8	Coal 1.4	Coal 2.0	Lignite 0.5	Oil 2.5
Power unit size, MW	500	200	700	1,000	500	500	500	500	500
Heat rate, kcal/kWh	2,268	2,319	2,243	2,193	2,268	2,268	2,268	2,268	2,268
No. FGD trains	4	2	6	8	4	4	4	4	4
Sulfur removal, %	90	90	90	90	90	90	90	90	90
Sulfur in fuel, % as-fired basis	3.12	3.12	3.12	3.12	0.66	1.30	1.80	0.40	2.50
Sulfur in flue gas, % of input	95	95	95	95	95	95	95	95	100
Heating value, kcal/kg	5,830	5,830	5,830	5,830	5,280	7,000	6,110	4,390	10,480
Relative gas rate	100.00	40.89	138.44	193.33	102.46	99.02	99.48	105.11	83.26
Relative product rate	100.00	40.89	138.44	193.33	23.38	34.72	55.07	17.05	46.95

results in a projected emission rate of 2,437 kg/hr of sulfur. The relative product ratio, again using the base case as the datum, is therefore

$$(2{,}437 \text{ kg/hr})/(5{,}188 \text{ kg/hr}) = 0.47$$

Relative product rates for other power plant sizes can be calculated using the known relative product rate and the size and heat-rate ratios in the same manner as described for the gas rate.

Number of Trains--

The number of scrubber trains for the range of power plant sizes evaluated in this study is varied between two and eight depending on power plant sizes. The number is based on an assumed scrubber capacity of 125-MW/train for FGD processing equipment. The numer of trains affects gas-related process equipment costs and ED&S costs. Product-related equipment areas such as the raw material and disposal areas are independent of the number of scrubbing trains and are, therefore, assumed to consist of the same number of processing trains regardless of power plant size.

Cost-Capacity Factors--

Costs for FGD processing areas for the case variations are projected from the base-case estimate using the "six-tenths factor" method for exponentially scaling costs as a function of the relative throughput ratio raised to an exponential power (8). Cost-capacity exponential scaling factors for each processing area are given in the equipment lists for each process.

The scaling equation is of the form $\dfrac{\text{Cost (A)}}{\text{Cost (B)}} = \left(\dfrac{\text{Capacity (A)}}{\text{Capacity (B)}}\right)^{\text{exp}}$

Pond Construction--

Pond construction costs are calculated individually for the case variations based on the lifetime quantity of sludge to be disposed. Pond design (depth and area) is optimized to result in a minimum cost pond; consequently, the cost does not vary linearly with product rate. The relationship between relative construction cost and relative product rate for limestone and lime sludges that settle to 40% solids is shown in Figure 1.

Scaling Procedure

Scaling of direct costs for plant size and fuel variations can be conducted using the factors discussed above. Procedures described in the premises are used for projecting indirect costs. For illustrating the procedures of scaling, calculations for the 200-MW, 3.5% sulfur limestone sludge process results using the base-case data are given below.

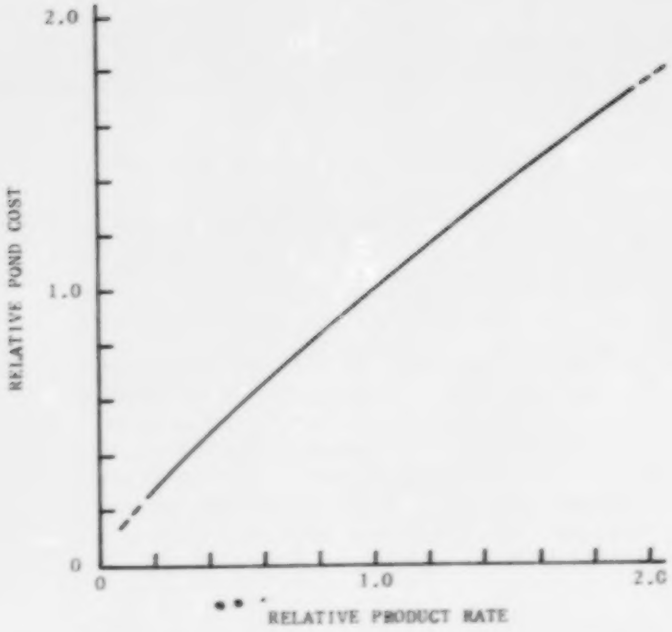


Figure 1. Effect of relative product rate on relative pond cost (relative product rate for 500-MW, 3.5% sulfur coal equals 1.0; based on 15% solids sludge settling to 40% solids).

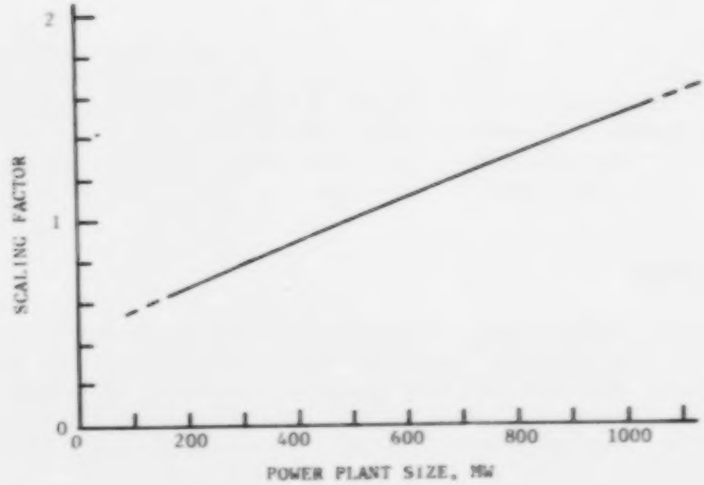


Figure 2. Effect of power plant size on scaling factor for operating labor and supervision cost.

Capital Investment Costs--

Procedures for scaling limestone process capital investment requirements are illustrated in Table 6 for the 200-MW, 3.5% sulfur fuel case. Process equipment costs are scaled for each processing area using the cost-capacity factors. For equipment areas whose sizes are dependent on gas rate, the number of absorber trains (if different from the base case) must also be included. For areas whose sizes are dependent on product rate the number of trains is assumed constant.

For areas that are primarily dependent on gas rate, the equipment cost is:

$$\text{Cost B} = \text{Cost A}\ [T_B/T_A]\,[G_B/T_B)/(G_A/T_A)]^{exp}$$

For areas dependent on product rate the equipment cost is:

$$\text{Cost B} = \text{Cost A}\ [P_B/P_A]^{exp}$$

where:

Cost A is the datum process equipment cost for the equipment area,
Cost B is the process equipment cost being scaled for the same area,
G_A and G_B are the relative gas rates,
P_A and P_B are the relative product rates,
T_A and T_B are the number of trains, and
exp is the cost-capacity factor for the equipment area shown in the equipment lists.

Services and miscellaneous costs are estimated as a percentage of the equipment costs as described in the premises. Scaled pond construction costs excluding land are shown in Figure 1. ED&S costs are calculated using the formula based on the number of major equipment items. In the illustration the 200-MW power plant is assumed to utilize two trains. Inspection of the equipment list shows a reduction of gas-related major equipment items to 69 (from 89 for the 500-MW power plant with 4 trains).

The remaining items including indirect investment costs, contingency, other capital charges, and working capital are calculated as described in the premises.

Land costs for the waste disposal pond are scaled using Figure 1. Land costs for stacking and intermittent storage are scaled using the relative product rates. Process land costs for the installed equipment can be acceptably scaled using the power plant size ratio.

Annual Revenue Requirements

Raw material and conversion costs are scaled using the appropriate relative gas and product rates and scale factors as described below and illustrated in Table 7.

TABLE 6. CAPITAL INVESTMENT SCALING ILLUSTRATION - LIMESTONE SLUDGE PROCESS BASE CASE SCALED TO 200 MW

	(500-MW cost)(scaling formula)	200-MW cost, k$
Process Equipment		
Area Basis		
1 Product	$(1,824)(0.409/1.000)^{0.73} =$	950
2 Product	$(2,062)(0.409/1.000)^{0.70} =$	1,103
3 Gas	$(4,950)[(0.409/2)/(1.000/4)]^{0.63}\ (2/4) =$	2,158
4 Gas	$(9,458)[(0.409/2)/(1.000/4)]^{0.74}\ (2/4) =$	4,076
5 Gas	$(1,292)[(0.409/2)/(1.000/4)]^{0.75}\ (2/4) =$	556
6 Product	$(2,164)(0.409/1.000)^{0.54} =$	1,335
Total		10,178
Services and miscellaneous (6% of total)		611
Pond construction	(approx 0.496 from Figure 7)(5,481) =	2,717
Total direct investment		13,506
Indirect Investment		
ED&S	$(8,900)(1.294)(69) + (0.076)(2.717)^{0.67}(10^6) =$ 795,000 + 148,000 =	943
A&E	(795)(0.25) + (148)(0.10) =	214
Construction expense	$[(0.25)(10.789)^{0.83} + (0.15)(2.717)^{0.83}](10^6) =$	2,098
Contractor fees	$(0.096)(13.506)^{0.76}(10^6) =$	694
Total		17,455
Contingency	(17,455)(0.20) =	3,491
Total fixed investment		20,946
Other Capital Charges		
Allowance for startup and modifications	(20,946 - 2,717)(0.10) =	1,823
Interest during construction	(20,946)(0.12) =	2,514
Total depreciable investment		25,283
Disposal land	(approx 0.489 factor from Figure 7) (1,098,000 - 21,000)(0.490) =	546
Process land	(6 acres)(3,500)(200/500) =	8
Working capital		465
Total capital investment		26,302

TABLE 7. ANNUAL REVENUE REQUIREMENTS SCALING ILLUSTRATION -

LIMESTONE SLUDGE PROCESS BASE CASE SCALED TO 200 MW

	(500-MW cost)(scaling formula)	200-MW cost, k$
Direct Costs[a]		
Raw materials	(1,181)(0.409) =	483
Conversion costs		
Operating labor and supervision	(301)(0.68 from Figure 8) =	205
Steam	(839)(0.409) =	343
Process water	(27)(0.409) =	11
Electricity	[(47,967 - 600)(0.409) + 600](0.031 $/kWh) =	619
Maintenance	(13,506 - 2,717)(0.08) + (2,717)(0.03) =	945
Analyses	$(55)(0.409)^{0.6}$ =	32
Total conversion costs		2,155
Total direct costs		2,638
Indirect Costs		
Depreciation, interim replacement, insurance at 6% of total depreciable investment		1,517
Average cost of capital and taxes at 8.6% of total capital investment		2,262
Plant overhead at 50% of conversion costs less utilities		591
Administrative overhead at 10% of operating labor		21
Total indirect costs		4,391
Total annual revenue requirements		7,029

[a] For cases in which the unit costs for raw materials or utilities vary with consumption, annual quantities should be scaled in the same manner as discussed below, and then the appropriate unit costs should be applied to the scaled quantity to calculate annual cost.

Raw Materials--

Since raw material consumption is generally a function of the quantity of sulfur removed rather than the amount of flue gas to be scrubbed, raw material quantities are scaled proportional to the relative product rate.

Operating Labor and Supervision--

Labor and supervision requirements for FGD systems are not linear functions of either plant size or relative gas or product rates. For each process, operating labor and supervision requirements are estimated for the base case application considering process complexity and the type of byproduct produced. Although requirements are likely to change to a slight degree with changes in the design assumptions, the magnitude of the change is slight except for cases in which the plant size is varied. For this study operating labor and supervision requirements are not modified to account for fuel variations. These requirements are varied, however, to account for changes resulting from variations in power plant size. Figure 2 shows the relationship between power unit size and relative labor and supervision requirements utilized for projecting labor requirements.

Utilities--

With the exception of electricity, utilities are scaled as functions of either the relative gas or relative product rates. Utilities such as reheat energy and fan electricity are scaled proportionally to the relative gas rate, whereas utilities such as fuel oil for calcination or electricity for H_2SO_4 production are scaled proportionally to the relative product rate. Base case utility requirements for utilities such as process steam, process water, fuel oil, and heat credit are obtained from the material balance. Electricity requirements are obtained from the equipment lists where the motor horsepower is identified. In addition to this electricity, however, a part of the electrical consumption is utilized for functions such as lighting and does not vary with relative gas and product rates. In this study 600,000 kWh (100 kW x 6000 hr) is used. This quantity must be subtracted from the total base case electricity requirement and recombined after scaling as illustrated in Table 7.

Analyses--

Analyses costs for the case variations are scaled by multiplying the base case analyses requirements by the relative product ratio raised to the 0.6 exponential power.

Other Costs--

The remaining annual revenue requirement costs are determined as percentages of the above scaled costs or capital investment costs as described in the premises.

ACCURACY OF RESULTS AND TECHNICAL QUALIFICATIONS

In the projection of FGD economics the stage of development and the amount of information available to estimate process costs are major factors affecting accuracy of the results. The stage of development is an indication of the process modifications which may be required to achieve reliable commercial operation and is difficult to quantify in terms of cost increases or decreases likely to result from technological advances. Although the processes in this study differ widely in stage of development, no attempt is made to numerically differentiate accuracies on this basis.

The amount of information available upon which to base economic evaluations (site characteristics, detailed process design data, and operating experience, for example) reduces the uncertainty of process costs by defining in greater detail premises upon which cost estimates are based. The accuracy of cost estimates as a function of information available is generally established.

Based on a comparison of the data available for estimating costs of some of the FGD processes in this study with American Association of Cost Engineers guidelines (9) for capital cost estimating, the capital costs of actual installations may vary from these cost estimates within a range of +50% (actual costs may be higher) to -30% (actual costs may be lower). This range of variations does not include the effect of project scope variations such as designing with spare scrubbing trains or eliminating reheat.

Estimates of revenue requirements are not expected to exhibit as much variability as the capital cost estimates. Since the projections of raw material and utility requirements are generally based on actual test data or process chemistry, calculated quantities are generally considered to be more accurate than the capital cost estimates. However, capital charges based on capital cost account for a major portion of revenue requirements. Considering the range of variability discussed above for capital costs, the revenue requirements may vary from these cost estimates within a nominal range of +25% (actual costs may be higher) to -15% (actual costs may be lower). However, the accuracy graphs in the appendixes reflect the specific range of accuracy associated with projected changes in the investment, rather than the nominal +25% to -15% discussed above.

The economic evaluations of some of the processes in this study are based on previous detailed evaluations prepared for the U.S. Environmental Protection Agency. For these processes information in considerable detail is available and the ranges of accuracy can be reduced. The ranges of accuracy for the cost estimates in this study thus vary from the preliminary-evaluation range of +50% to -30% to smaller ranges of +30% to -20% and +20% to -15%, depending on the information available for the particular process. The estimated ranges of accuracy for the processes evaluated, based on the amount of information available and previous experience with similar estimates, are discussed in the description of processes evaluated and are shown in the results.

RESULTS

Process and economic evaluation results for the nine FGD processes evaluated are summarized in Tables 8 through 17. Detailed results, flow diagrams, material balances, and equipment lists are shown in Appendixes A through I. Figures 3 and 4 show the economic results graphically, illustrating the accuracy ranges projected for each process. Capital costs are in mid-1979 U.S. dollars. Revenue requirements are in mid-1980 U.S. dollars.

Because the evaluations included within this report are based on generalized premises and limited actual cost data are available for some of the processes, no attempt is made to compare the projected costs with costs for actual site-specific installations. Limited cost data for actual installations may be obtained from the Phase I reports or from the periodic PEDCo reports (10).

TABLE 8. LIMESTONE SLUDGE PROCESS MATERIAL, ENERGY, AND COST SUMMARY

Fuel Percent sulfur	Coal 0.8	Coal 1.4	Coal 2.0	Coal 3.5	Lignite 0.5	Oil 2.5
Raw materials, kg/hr						
Limestone	6,000	8,900	14,000	25,500	4,300	12,000
End product						
Sludge						
m^3/hr	13.3	19.77	31.35	56.93	9.70	26.73
ft^3/hr	470.0	698.0	1,107.1	2,010.4	342.4	943.9
kg/hr	17,561	26,079	41,364	75,112	12,792	35,265
lb/hr	38,715	57,493	91,190	165,590	28,200	77,744
wt % solids	40	40	40	40	40	40
Energy						
Reheat, kcal/hr	18.06 M	17.45 M	17.53 M	17.62 M	18.52 M	14.67 M
Electricity, kcal/hr	16.98 M	16.66 M	17.14 M	18.13 M	17.27 M	14.40 M
Total - kcal/hr	35.04 M	34.11 M	34.67 M	35.75 M	35.79 M	29.07 M
- Btu/hr	139.2 M	135.6 M	137.5 M	141.9 M	141.9 M	115.5 M
- % input	3.27	3.18	3.23	3.33	3.34	2.71
Land						
Process, ha	3.7	3.7	3.7	3.7	3.7	3.7
Waste disposal, ha	38.6	51.8	74.6	123.0	29.8	65.8
Total - ha	42.3	55.5	78.3	126.7	33.5	69.5
- acres	104.5	137.1	193.5	313.1	82.8	171.7
Costs[a]						
Capital investment	39,995,000	41,634,000	45,516,000	53,083,000	39,036,000	40,643,000
Low range	34,112,000	35,526,000	38,863,000	45,376,000	33,285,000	34,705,000
High range	47,838,000	49,778,000	54,387,000	63,358,000	46,704,000	48,559,000
Annual revenue requirements	11,151,700	11,539,200	12,574,200	14,638,000	10,945,400	11,385,400
Low range	9,933,800	10,279,000	11,206,400	13,064,500	9,752,100	10,168,000
High range	12,775,200	13,219,500	14,397,200	16,736,100	12,536,500	13,008,300

a. Accuracy range: +20% to -15%.

TABLE 9. LIMESTONE SLUDGE PROCESS SIZE VARIATIONS,

MATERIAL, ENERGY, AND COST SUMMARY

MW Fuel Percent sulfur	200 Coal 3.5	500 Coal 3.5	700 Coal 3.5	1,000 Coal 3.5
Raw materials, kg/hr				
Limestone	10,400	25,500	35,300	49,300
End product				
m^3/hr	23.28	56.93	78.82	110.07
ft^3/hr	822.0	2,010.4	2,783.1	3,886.7
kg/hr	30,713	75,112	103,983	145,216
lb/hr	67,710	165,590	229,240	320,140
wt % solids	40	40	40	40
Energy				
Reheat, kcal/hr	7.21 M	17.62 M	24.39 M	34.07 M
Electricity, kcal/hr	7.72 M	18.13 M	24.74 M	33.68 M
Total - kcal/hr	14.93 M	35.75 M	49.13 M	67.75 M
- Btu/hr	59.2 M	141.79 M	194.95 M	268.83 M
- % input	3.39	3.33	3.30	3.26
Land				
Process, ha	3.1	3.7	3.8	4.2
Waste disposal, ha	61.0	123.0	159.0	209.0
Total - ha	64.1	126.7	162.8	213.2
- acres	158.3	313.1	402.3	526.9
Costs[a]				
Capital investment	26,302,000	53,083,000	70,967,000	93,941,000
Low range	22,481,000	45,376,000	60,657,000	80,296,000
High range	31,397,000	63,358,000	84,713,000	112,135,000
Annual revenue requirements	7,029,100	14,638,000	19,734,300	26,384,700
Low range	6,260,400	13,064,500	17,619,200	23,573,800
High range	8,054,000	16,736,100	22,554,300	30,132,600

a. Accuracy range: +20% to -15%.

TABLE 10. LIME SLUDGE PROCESS MATERIAL, ENERGY, AND COST SUMMARY

Fuel Percent sulfur	Coal 0.8	Coal 1.4	Coal 2.0	Coal 3.5	Lignite 0.5	Oil 2.5
Raw materials, kg/hr						
Lime	2,400	3,500	5,600	10,200	1,700	4,800
End product						
Sludge						
m^3/hr	10.22	15.17	24.07	43.70	7.44	20.52
ft^3/hr	360.3	535.0	848.6	154.1	262.4	723.4
kg/hr	13,394	19,891	31,549	57,290	9,756	26,898
lb/hr	29,529	43,851	69,553	126,300	21,509	59,298
wt % solids	40	40	40	40	40	40
Energy						
Reheat, kcal/hr	18.00 M	17.39 M	17.47 M	17.56 M	18.46 M	14.62 M
Electricity, kcal/hr	16.82 M	16.34 M	16.54 M	16.89 M	17.21 M	13.88 M
Total - kcal/hr	34.82 M	33.73 M	34.01 M	34.45 M	35.67 M	28.50 M
- Btu/hr	138.2 M	133.9 M	135.0 M	136.7 M	141.5 M	113.1 M
- % input	3.25	3.14	3.17	3.21	3.33	2.51
Land						
Process, ha	2.5	2.5	2.5	2.5	2.5	2.5
Waste disposal, ha	32.5	44.8	63.5	104.0	25.5	54.9
Total - ha	35.0	47.3	66.0	106.5	28.0	57.4
- acres	86.5	116.9	163.1	262.4	69.2	141.8
Costs[a]						
Capital investment	37,795,000	38,912,000	41,952,000	47,743,000	37,165,000	37,286,000
Low range	32,244,000	33,216,000	35,841,000	40,853,000	31,695,000	31,855,000
High range	45,196,000	46,507,000	50,099,000	56,932,000	44,458,000	44,526,000
Annual revenue requirements	11,064,200	11,498,200	12,644,700	14,972,100	10,836,300	11,387,700
Low range	9,912,000	10,320,100	11,386,000	13,562,700	9,698,200	10,271,300
High range	12,600,400	13,069,200	14,323,000	16,851,500	12,353,800	12,876,100

a. Accuracy range: +20% to -15%.

TABLE 11. DOUBLE-ALKALI SLUDGE PROCESS MATERIAL, ENERGY, AND COST SUMMARY

Fuel Percent sulfur	Coal 0.8	Coal 1.4	Coal 2.0	Coal 3.5	Lignite 0.5	Oil 2.5
Raw materials, kg/hr						
Lime	2,277	3,381	5,363	9,737	1,659	4,572
Soda ash	186	277	439	797	136	374
End product						
Sludge						
m^3/hr	6.98	10.37	16.45	29.87	5.09	14.03
ft^3/hr	246.6	366.2	580.9	1,054.9	179.6	495.3
kg/hr	9,075	13,476	21,375	38,815	6,610	18,223
lb/hr	20,006	29,710	47,123	85,570	14,573	40,175
wt % solids	55	55	55	55	55	55
Energy						
Reheat, kcal/hr	18.06 M	17.45 M	17.53 M	17.62 M	18.52 M	14.67 M
Electricity, kcal/hr	8.08 M	7.99 M	8.33 M	9.03 M	8.18 M	7.02 M
Total - kcal/hr	26.14 M	25.44 M	25.86 M	26.65 M	26.70 M	21.69 M
- Btu/hr	103.7 M	101 M	102.6 M	105.8 M	106 M	86.1 M
- % input	2.48	2.41	2.45	2.52	2.54	1.91
Land						
Process, ha	4.9	4.9	4.9	4.9	4.9	4.9
Waste disposal, ha	33.0	44.0	62.0	99.0	31.1	48.0
Total - ha	37.9	48.9	66.9	103.9	36.0	52.9
- acres	150.4	194.0	265.5	412.3	89.1	209.9
Costs[a]						
Capital investment	40,537,000	42,179,000	46,045,000	53,231,000	39,595,000	40,659,000
Low range	32,581,000	33,926,000	37,075,000	43,004,000	31,817,000	32,733,000
High range	52,472,000	54,559,000	59,500,000	68,662,000	51,261,000	52,546,000
Annual revenue requirements	11,173,000	11,793,600	13,080,000	16,010,600	10,828,000	11,879,500
Low range	9,528,500	10,091,700	11,258,600	14,359,800	92,177,000	10,251,200
High range	13,639,700	14,346,600	15,811,900	19,169,400	13,234,300	14,321,700

[a] Accuracy range: +30% to -20%.

TABLE 12. SEAWATER PROCESS MATERIAL, ENERGY, AND COST SUMMARY

Fuel	Coal	Coal	Lignite	Oil	Low reheat coal
Percent sulfur	1.4	0.8	0.5	2.5	1.4
End product					
Seawater					
liters/hr	71,385,400	51,526,200	35,692,700	83,214,800	71,385,400
kg/hr	72,124,300	52,041,400	36,062,200	84,071,900	72,124,300
lb/hr	158,864,200	114,731,700	79,432,100	185,346,900	158,864,200
Energy					
Reheat, kcal/hr	28.70 M	29.69 M	30.46 M	24.13 M	14.46 M
Electricity, kcal/hr	15.91 M	14.89 M	13.88 M	15.47 M	15.91 M
Total - kcal/hr	44.61 M	44.58 M	44.34 M	39.60 M	30.37 M
- Btu/hr	177.0 M	176.9 M	175.9 M	157.1 M	120.5 M
- % input	4.22	4.22	4.21	3.49	2.82
Land					
Process, ha	2.4	2.4	2.4	2.4	2.4
Total - ha	2.4	2.4	2.4	2.4	2.4
- acres	6	6	6	6	6
Costs[a]					
Capital investment	30,048,000	29,590,000	29,068,000	27,937,000	28,582,000
Low range	21,157,000	20,838,000	20,471,000	19,691,000	20,106,000
High range	44,868,000	44,177,000	43,397,000	41,682,000	42,707,000
Annual revenue requirements	8,707,100	8,667,100	8,516,800	8,575,600	7,837,700
Low range	6,972,700	6,960,500	6,840,700	6,968,800	6,185,700
High range	11,597,700	11,511,800	11,310,300	11,253,400	10,590,900

a. Accuracy range: +50% to -30%.

TABLE 13. LIME GYPSUM (SAARBERG-HOLTER) PROCESS

MATERIAL, ENERGY, AND COST SUMMARY

Fuel Percent sulfur	Coal 0.8	Coal 1.4	Coal 2.0	Coal 3.5	Lignite 0.5	Oil 2.5
Raw materials, kg/hr						
Lime	2,255	3,344	5,297	9,625	1,634	4,525
Formic acid	1.8	2.7	4.3	7.9	1.3	3.7
Flocculant	0.18	0.26	0.42	0.76	0.13	0.36
Nalco	0.02	0.03	0.04	0.08	0.01	0.04
End product						
Gypsum						
m^3/hr	6.06	9.00	14.27	25.92	4.41	12.17
ft^3/hr	214.1	317.6	503.9	915.3	155.7	429.8
kg/hr	8,263	12,260	19,445	35,320	6,008	16,586
lb/hr	18,200	27,000	42,830	77,800	13,230	36,530
wt % solids	80	80	80	80	80	80
Energy						
Reheat, kcal/hr	18.14 M	17.53 M	17.61 M	17.70 M	18.61 M	14.74 M
Electricity, kcal/hr	12.59 M	13.76 M	16.34 M	22.00 M	12.13 M	13.78 M
Total - kcal/hr	30.73 M	31.29 M	33.95 M	39.70 M	30.74 M	28.52 M
- Btu/hr	121.94 M	124.16 M	134.71 M	157.53 M	121.98 M	113.17 M
- % input	2.89	2.93	3.17	3.67	2.89	2.51
Land						
Process, ha	4.46	4.46	4.46	4.46	4.46	4.46
Byproduct storage, ha	0.4	0.4	0.4	0.4	0.4	0.4
Total - ha	4.86	4.86	4.86	4.86	4.86	4.86
- acres	12	12	12	12	12	12
Costs[a]						
Capital investment	35,481,000	36,472,000	39,173,000	44,024,000	34,905,000	34,802,000
Low range	24,988,000	25,701,000	27,631,000	31,114,000	24,574,000	24,557,000
High range	52,970,000	54,424,000	58,407,000	65,541,000	52,124,000	51,878,000
Annual revenue requirements	9,825,900	10,303,700	11,443,300	13,706,300	9,571,100	10,347,600
Low range	7,791,500	8,214,400	9,201,300	11,192,900	7,568,900	8,362,400
High range	13,216,300	13,785,800	15,179,800	17,895,300	12,908,000	13,656,200

a. Accuracy range: +50% to -30%.

TABLE 14. JET-BUBBLING LIMESTONE (CHIYODA THOROUGHBRED 121) PROCESS MATERIAL, ENERGY, AND COST SUMMARY

Fuel Percent sulfur	Coal 0.8	Coal 1.4	Coal 2.0	Coal 3.5	Lignite 0.5	Oil 2.5
Raw materials, kg/hr						
Limestone	4,067	6,048	9,586	17,400	2,964	8,180
End product						
Gypsum						
m^3/hr	6.19	9.18	14.57	26.45	4.50	12.42
ft^3/hr	218.42	324.30	514.42	934.14	159.06	438.54
kg/hr	8,421	12,503	19,834	36,015	6,132	16,908
lb/hr	18,565	27,565	43,725	79,400	13,520	37,275
wt % solids	80	80	80	80	80	80
Energy						
Reheat, kcal/hr	18.61 M	17.98 M	18.07 M	18.16 M	19.09 M	15.12 M
Electricity, kcal/hr	17.32 M	16.97 M	17.42 M	18.35 M	16.63 M	14.64 M
Total - kcal/hr	35.93 M	34.95 M	35.49 M	36.51 M	35.72 M	29.76 M
- Btu/hr	142.57 M	138.68 M	140.82 M	144.87 M	141.74 M	118.09 M
- % input	3.35	3.26	3.31	3.40	3.34	2.62
Land						
Process, ha	4.46	4.46	4.46	4.46	4.46	4.46
Byproduct storage, ha	0.4	0.4	0.4	0.4	0.4	0.4
Total - ha	4.86	4.86	4.86	4.86	4.86	4.86
- acres	12	12	12	12	12	12
Costs[a]						
Capital investment	42,002,000	42,007,000	43,819,000	47,017,000	42,095,000	38,532,000
Low range	29,538,000	29,545,000	30,826,000	33,091,000	29,602,000	27,118,000
High range	62,774,000	62,776,000	65,474,000	70,227,000	62,917,000	57,556,000
Annual revenue requirements	10,948,500	10,919,500	11,360,700	12,160,100	10,998,700	10,219,200
Low range	8,524,700	8,496,000	8,831,900	9,446,000	8,568,900	8,003,400
High range	14,988,200	14,958,600	15,575,600	16,683,500	15,048,200	13,912,300

a. Accuracy range: +50% to -30%.

TABLE 15. MAGNESIUM OXIDE PROCESS MATERIAL, ENERGY, AND COST SUMMARY

Fuel Percent sulfur	Coal 0.8	Coal 1.4	Coal 2.0	Coal 3.5	Lignite 0.5	Oil 2.5
Raw materials						
MgO, kg/hr	51	76	119	218	38	103
Catalyst, liters/hr	0.1	0.1	0.2	0.3	0.1	0.1
Agricultural limestone, kg/hr	431	832	1,255	420	398	0
End product						
Sulfuric acid						
liters/hr	2,041	3,026	4,800	8,717	1,485	4,090
kg/hr	3,735	5,538	8,785	15,951	2,717	7,484
lb/hr	8,233	12,210	19,367	35,167	5,990	16,500
wt % H_2SO_4	100	100	100	100	100	100
Energy						
Reheat, kcal/hr	18.57 M	17.95 M	18.03 M	18.12 M	19.05 M	15.09 M
Electricity, kcal/hr	16.38 M	16.57 M	17.87 M	20.66 M	16.38 M	12.94 M
Oil, kcal/hr	7.90 M	11.73 M	18.60 M	33.78 M	5.75 M	15.86 M
Heat credit, kcal/hr	(0.84 M)	(1.25 M)	(1.98 M)	(3.60 M)	(0.61 M)	(1.69 M)
Total - kcal/hr	42.01 M	45.00 M	52.52 M	68.96 M	40.57 M	42.20 M
- Btu/hr	166.7 M	178.6 M	208.4 M	273.6 M	161.0 M	167.4 M
- % input	3.89	4.14	4.81	6.26	3.58	3.72
Land						
Process, ha	4.86	4.86	4.86	4.86	4.86	4.86
Total - ha	4.86	4.86	4.86	4.86	4.86	4.86
- acres	12	12	12	12	12	12
Costs[a]						
Capital investment	48,926,000	52,043,000	58,108,000	68,434,000	47,115,000	44,591,000
Low range	39,252,000	41,757,000	46,632,000	54,934,000	37,798,000	35,799,000
High range	63,436,000	67,472,000	75,324,000	88,685,000	61,090,000	57,779,000
Annual revenue requirements	12,949,500	13,651,200	15,114,300	17,546,900	12,573,900	11,984,600
Low range	10,999,500	11,576,400	12,759,400	14,809,500	10,697,100	10,208,300
High range	15,874,400	16,763,000	18,592,700	21,652,700	15,389,100	14,646,600

a. Accuracy range: +30% to -20%.

TABLE 16. SODIUM SULFITE (WELLMAN-LORD) PROCESS

MATERIAL, ENERGY, AND COST SUMMARY

Fuel Percent sulfur	Coal 0.8	Coal 1.4	Coal 2.0	Coal 3.5	Lignite 0.5	Oil 2.5	Sulfur production coal 3.5
Raw materials							
Sodium carbonate, kg/hr	218	323	512	930	159	437	930
Catalyst, liters/hr	0.07	0.10	0.16	0.29	0.05	0.14	-
Agricultural limestone, kg/hr	431	832	1,254	420	398	-	420
Filter aid, kg/hr	2	4	6	11	2	5	11
Natural gas, m^3/hr	-	-	-	-	-	-	2,311
End product							
100% sulfuric acid							
liters/hr	1,887	2,803	4,446	8,073	1,375	3,790	-
kg/hr	3,453	5,129	8,136	14,774	2,516	6,935	-
lb/hr	7,613	11,307	17,937	32,570	5,546	15,290	-
Sodium sulfate							
kg/hr	277	410	650	1,181	201	555	1,181
lb/hr	610	903	1,433	2,603	443	1,223	2,603
Sulfur							
kg/hr	-	-	-	-	-	-	4,802
lb/hr	-	-	-	-	-	-	10,857
Energy							
Reheat, kcal/hr	15.47 M	14.95 M	15.02 M	15.10 M	15.87 M	12.57 M	15.10 M
Process steam, kcal/hr	10.90 M	16.19 M	25.68 M	46.64 M	7.94 M	21.90 M	47.20 M
Electricity, kcal/hr	17.99 M	18.68 M	20.90 M	25.73 M	17.72 M	15.44 M	25.59 M
Natural gas, kcal/hr	-	-	-	-	-	-	20.56 M
Heat credit, kcal/hr	(0.46 M)	(0.69 M)	(1.09 M)	(1.98 M)	(0.34 M)	(0.93 M)	(2.79 M)
Total - kcal/hr	43.90 M	49.13 M	60.51 M	85.49 M	41.19 M	48.98 M	105.66 M
- Btu/hr	174.2 M	194.9 M	240.1 M	339.2 M	163.4 M	194.4 M	419.3 M
- % input	4.13	4.64	5.73	8.14	3.78	4.53	9.93
Land							
Process, ha	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Total - ha	3.2	3.2	3.2	3.2	3.2	3.2	3.2
- acres	8	8	8	8	8	8	8
Costs[a]							
Capital investment	46,836,000	50,307,000	56,939,000	68,722,000	44,837,000	44,215,000	71,342,000
Low range	37,581,000	40,372,000	45,706,000	55,187,000	35,975,000	35,504,000	57,343,000
High range	60,719,000	65,210,000	73,789,000	89,025,000	58,131,000	57,280,000	92,341,000
Annual revenue requirements	12,218,300	13,081,000	14,802,200	17,886,400	11,754,700	11,801,900	21,015,700
Low range	10,434,500	11,164,000	12,629,900	15,257,400	10,048,100	10,124,600	18,296,500
High range	14,893,900	15,956,500	18,060,200	21,829,800	14,314,400	14,317,700	24,094,700

a. Accuracy range: +30% to -20%.

TABLE 17. CARBON ADSORPTION PROCESS MATERIAL, ENERGY, AND COST SUMMARY

Fuel	Coal	Coal	Coal	Coal	Lignite	Oil
Percent sulfur	0.8	1.4	2.0	3.5	0.5	2.5
Raw materials						
Sand, kg/hr	106	151	257	454	76	212
Char, kg/hr	544	816	1,300	2,359	408	1,104
Anthracite coal, kg/hr	1,179	1,754	1,255	5,035	862	2,359
End product						
Sulfur						
lb/hr	2,533	3,800	6,000	10,900	1,867	5,133
kg/hr	1,149	1,724	2,752	4,944	847	2,328
Char fines and RESOX waste						
lb/hr	2,267	3,400	5,366	9,733	1,633	4,567
kg/hr	1,028	1,542	2,434	4,415	741	2,071
Energy						
Electricity, kcal/hr	3.86 M	4.08 M	3.83 M	6.01 M	3.74 M	3.99 M
Process steam, kcal/hr	0.15 M	0.23 M	0.36 M	0.66 M	0.11 M	0.31 M
Fuel oil, kcal/hr	6.33 M	9.41 M	14.92 M	27.10 M	4.61 M	12.72 M
Heat credit, kcal/hr	(3.46 M)	(5.14 M)	(8.16 M)	(14.82 M)	(2.52 M)	(6.96 M)
Total - kcal/hr	6.88 M	8.58 M	10.95 M	18.95 M	5.94 M	10.06 M
- Btu/hr	27.3 M	34.0 M	43.4 M	75.2 M	23.6 M	39.9 M
- % input	0.61	0.76	0.97	1.68	0.52	0.89
Land						
Process, ha	4.86	4.86	4.86	4.86	4.86	4.86
Total - ha	4.86	4.86	4.86	4.86	4.86	4.86
- acres	12	12	12	12	12	12
Costs[a]						
Capital investment	51,195,000	54,220,000	60,834,000	73,511,000	49,485,000	53,730,000
Low range	33,109,000	39,533,000	44,350,000	53,617,000	36,153,000	39,104,000
High range	69,978,000	78,698,000	88,308,000	106,666,000	71,704,000	78,105,000
Annual revenue requirements	13,899,100	15,803,600	19,982,700	28,489,400	12,780,100	17,542,000
Low range	10,747,500	12,844,600	16,658,600	24,473,000	10,094,500	14,600,600
High range	18,174,700	20,735,200	25,522,900	35,183,500	17,256,100	22,445,100

a. Accuracy range: +50% to -30%.

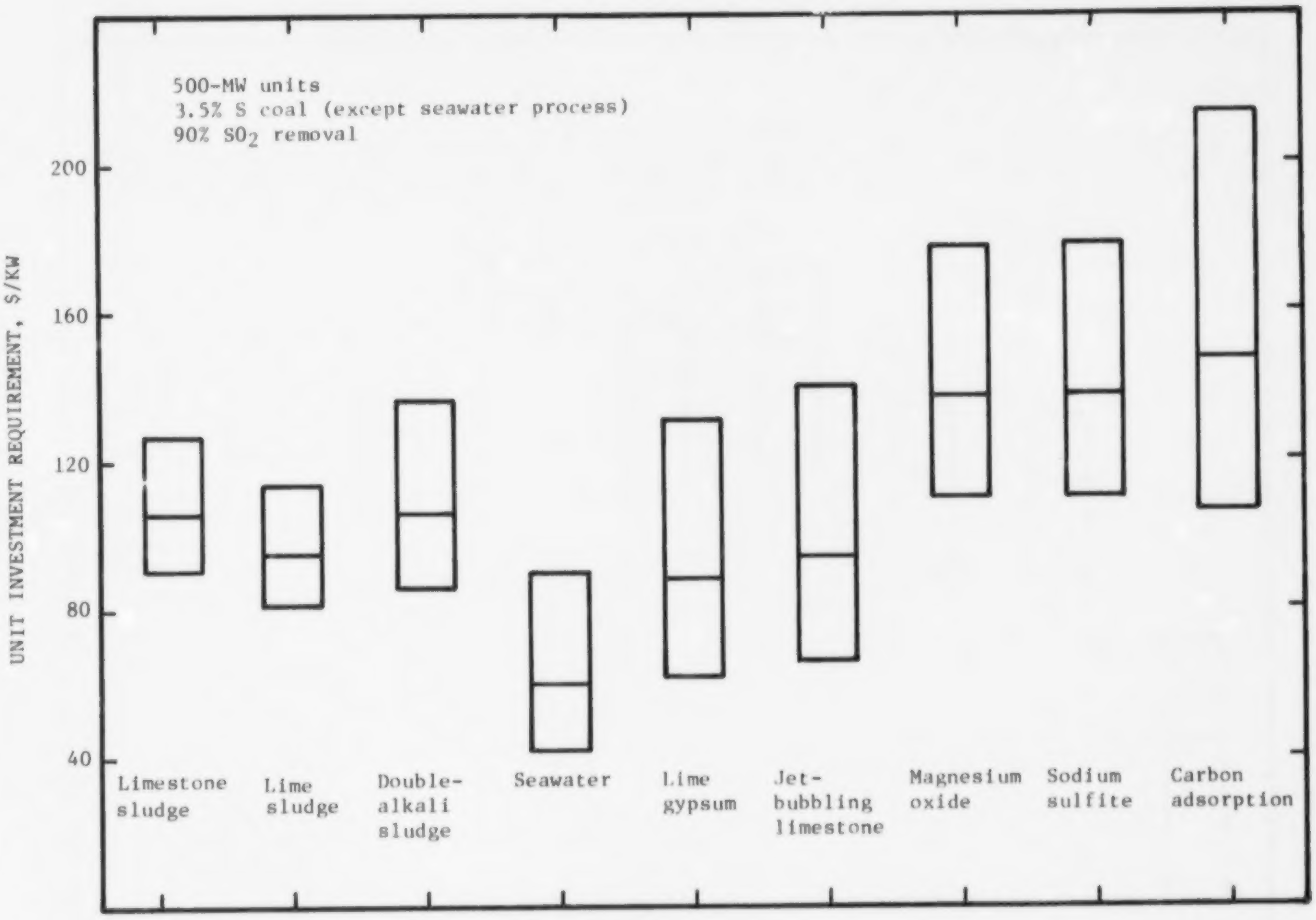


Figure 3. Base-case unit investment range for alternate processes.

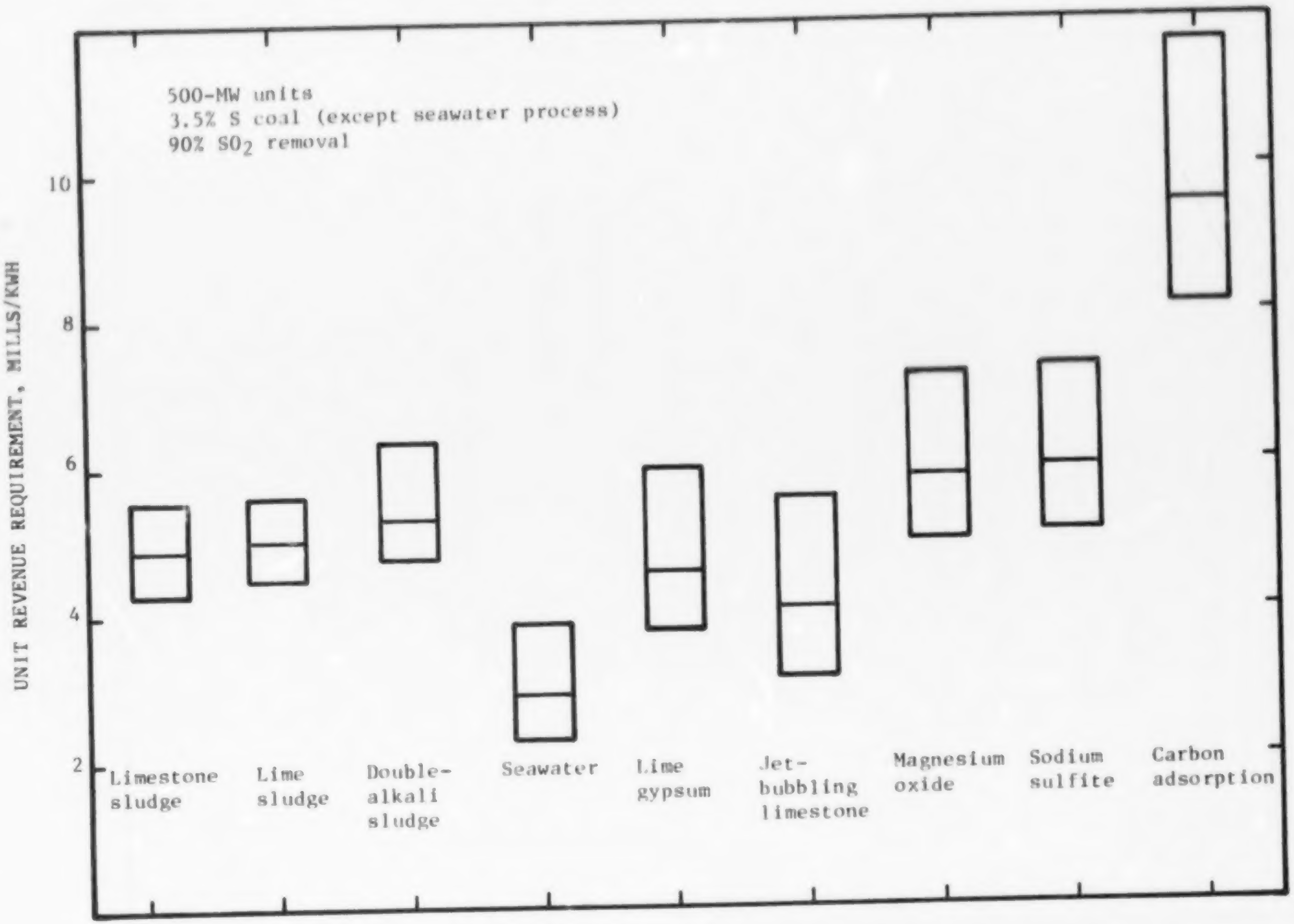


Figure 4. Base-case unit revenue requirement range for alternate processes.

ELEMENTS IN SELECTING AN FGD SYSTEM

Many complex interrelated factors affect FGD process selection for a specific site. To facilitate selection two decision aids are presented in this section. These aids are designed to help the user eliminate FGD processes which are not applicable to his plant and to rate those processes that apply. After these steps are completed, additional detailed information is required to further delineate the applicability of a specific process to a plant. However, by initially selecting the more applicable FGD processes, a considerable amount of effort and expense can be saved because preliminary engineering design and cost estimates need be prepared for fewer processes. It must be emphasized that these decision aids will not provide the user with an optimum system for his case, but will only guide him to a number of possible processes that meet his initial requirements.

FACTORS INVOLVED IN FGD PROCESS SELECTION

In making a preliminary selection of FGD processes, four main areas of concern must be evaluated: (1) raw material requirements, (2) end products, (3) performance requirements, and (4) plant site considerations.

An evaluation of these factors will eliminate some types of FGD processes from further consideration. Planning resources can then be directed to processes which are applicable to the specific site.

Figure 5, an FGD selection matrix, summarizes key factors applied to the 12 FGD processes identified for the Phase I study in 1977. The cross-hatched boxes in this figure represent those raw materials, end products, performance requirements, or other special conditions applicable to that process. It must be emphasized that the cross-hatched boxes under the performance requirements category should be eliminated with time as processes are demonstrated for alternate fuels. Under the performance area, cross-hatching is provided where a process has not been demonstrated. If a process is applicable only to new plants, it is cross-hatched in the last column. This figure is used by asking questions which apply to each key factor as described below.

Major Raw Material Requirements

1. Are large quantities of limestone available?
2. Are large quantities of lime available?

	Raw material requirements					End products				Performance requirements			New plant
	Lime-stone	Lime	Sea-water	Fuel[a]	H_2	Sludge	Acidic seawater	Gypsum	H_2SO_4 or S	Full scale demonstration			
										HI S coal	Lo S coal	HI S oil	
Limestone/sludge	▨					▨						▨	
Lime/sludge		▨				▨						▨	
Double alkali/sludge	▨					▨					▨	▨	
Seawater			▨				▨			▨	▨		
Limestone/gypsum	▨							▨			▨		
Lime/gypsum		▨						▨		▨	▨		
Double alkali/gypsum	▨							▨		▨	▨		
Jet bub. limestone	▨							▨		▨	▨		
Magnesium oxide				▨ [b]					▨		▨		
Sodium sulfite				▨ [c]					▨				
Carbon adsorption				▨					▨	▨	▨	▨	▨
Copper oxide					▨				▨	▨	▨	▨	▨
	1	2	3	4	5	6	7	8	9	10	11	12	13

[a] Gas or oil

[b] Used to calcine

[c] Only if sulfur is to be produced

Figure 5. FGD selection matrix.

3. Are large quantities of seawater available?

4. Are large quantities of gaseous or liquid fuel available?

5. Are large quantities of hydrogen available?

Major End Products

6. Can a calcium-sulfur sludge be tolerated?

7. Can acidic seawater be discharged?

8. Can large quantities of gypsum be sold or discarded?

9. Can sulfuric acid or sulfur be sold?

Performance Requirements

10. Can a process that has not achieved full-scale operation on high-sulfur (2.0% or greater) coal be used?

11. Can a process that has not achieved full-scale operation on low-sulfur (less than 2.0%) coal be used?

12. Can a process that has not achieved full-scale operation on high-sulfur oil be used?

Plant Site Considerations

13. Is the FGD process to be applied to a new plant?

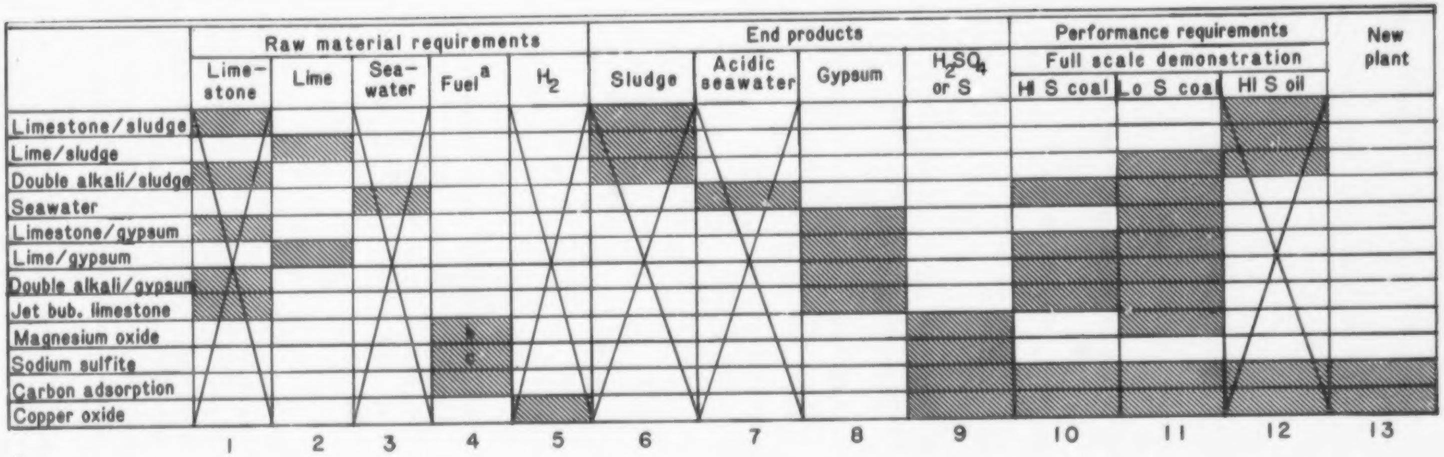
Example Use

When an answer to any of the above questions is no, the column under that condition should be crossed out. To select applicable processes, processes are eliminated where a cross-hatched box coincides with a crossed-out area. Two examples will illustrate this preliminary selection process.

Example No. 1--

Plant conditions: new 500-MW plant burning high-sulfur oil, located inland with strict water effluent restrictions. The plant is in an industrial area with byproduct lime available and a demand for sulfuric acid, but with limited space. Oil and gas are available but hydrogen is not. High equipment availability is required. After obtaining this site information, the FGD selection matrix is used to narrow the FGD choices by asking the questions previously listed, as shown in Figure 6.

Under raw materials, limestone, seawater, and hydrogen are not available and columns 1, 3, and 5 are crossed out. Under end products,



	Raw material requirements					End products				Performance requirements			New plant
										Full scale demonstration			
	Lime-stone	Lime	Sea-water	Fuel[a]	H_2	Sludge	Acidic seawater	Gypsum	H_2SO_4 or S	HI S coal	Lo S coal	HI S oil	
Limestone/sludge	▨					▨						▨	
Lime/sludge		▨				▨						▨	
Double alkali/sludge	▨					▨					▨	▨	
Seawater			▨				▨			▨	▨		
Limestone/gypsum	▨							▨			▨		
Lime/gypsum		▨						▨		▨	▨		
Double alkali/gypsum	▨							▨		▨	▨		
Jet bub. limestone	▨							▨		▨	▨		
Magnesium oxide				▨ b					▨		▨		
Sodium sulfite				▨ c					▨				
Carbon adsorption				▨					▨	▨	▨	▨	▨
Copper oxide					▨				▨	▨	▨	▨	▨
	1	2	3	4	5	6	7	8	9	10	11	12	13

[a] Gas or oil

[b] Used to calcine

[c] Only if sulfur is to be produced

Figure 6. Example selection matrix for an inland, new 500-MW power plant with strict effluent restrictions burning high-sulfur oil.

sludge and acidic seawater cannot be tolerated and columns 6 and 7 are crossed out. Columns 10 and 11 dealing with coal do not apply. Column 12 is crossed out because a process that has not achieved full-scale operation on high-sulfur oil cannot be used. Column 13 is not crossed out because this is a new plant.

Reading horizontally across the table, a cross-hatched area which has been crossed out eliminates the corresponding process from consideration. Examination of the crossed-out chart as shown in Figure 6 shows the following processes remain for further consideration.

Lime gypsum
Magnesium oxide
Sodium sulfite

Example No. 2--

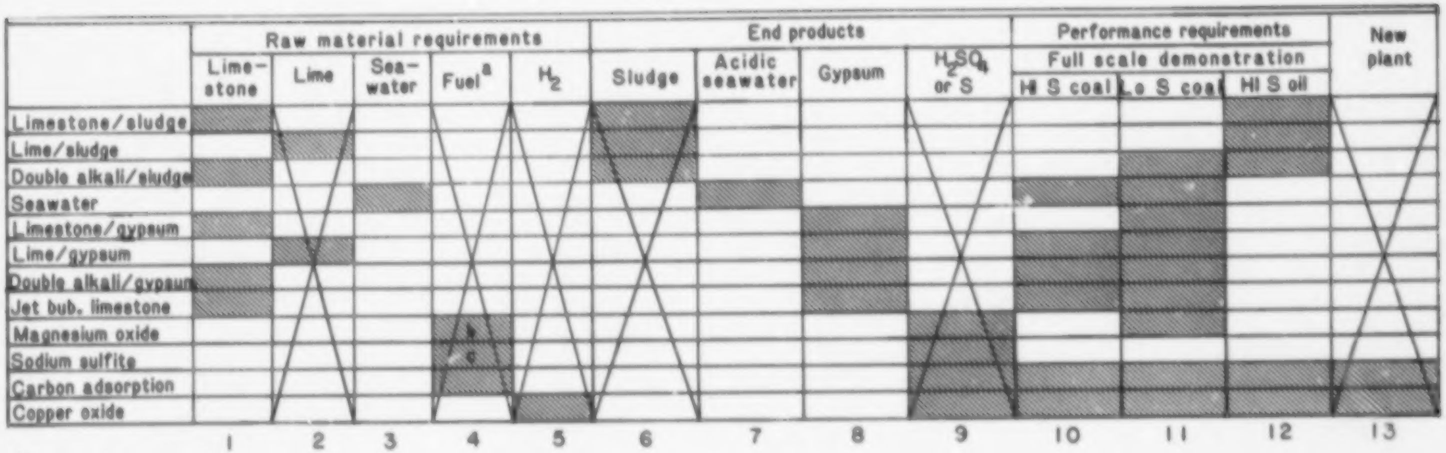
Plant conditions: existing plant burning 1.0% sulfur coal located on a seacoast with very limited open area and about 15 years of life remaining. A medium availability and 80% control efficiency are required. Limestone is available, but little liquid or gaseous fuel is available and no market for sulfur byproducts is evident.

Utilizing the selection matrix again (Figure 7), columns 2, 4, and 5 are crossed out because those raw materials are not available. Columns 6 and 9 are also crossed out because there is no space for sludge disposal and no sulfur market. Gypsum storage may be possible for a while, but it will have to be transported from the site after about 10 years. Under performance requirements, only the low-sulfur-coal column applies. Because a full-scale demonstration is not required (though desirable), this column is not crossed out. Column 13 is crossed out because this is not a new plant. As shown in Figure 7 this leaves the seawater and gypsum processes (except those using lime) remaining for further consideration.

PROCESS RATING

After a preliminary screening of FGD processes applicable to a specific case, a rating of these processes will further identify those that appear to be most feasible. Such a rating will not select the single best process but will help to establish priorities for studying processes.

There is no single uniform method for rating FGD processes which is used throughout the utility industry. A suggested rating chart is shown in Figure 8. This chart contains rating factors from 1 to 4 applied to six selection criteria for 12 FGD processes. The listed ratings, or "R factors," are based on judgements for each of the conditions which make up the criteria area as shown in the figure. Thus, under the first item, if an FGD process has been applied to many units, it is assigned a high score. A weighting factor is inserted by the user under the column labeled "W." This weighting factor enables the user to more heavily



	Raw material requirements					End products				Performance requirements			New plant
										Full scale demonstration			
	Lime-stone	Lime	Sea-water	Fuel[a]	H_2	Sludge	Acidic seawater	Gypsum	H_2SO_4 or S	Hi S coal	Lo S coal	Hi S oil	
Limestone/sludge	▨					▨						▨	
Lime/sludge		▨				▨						▨	
Double alkali/sludge	▨					▨					▨	▨	
Seawater			▨				▨			▨	▨		
Limestone/gypsum	▨							▨			▨		
Lime/gypsum		▨						▨		▨	▨		
Double alkali/gypsum	▨							▨		▨	▨		
Jet bub. limestone	▨							▨		▨	▨		
Magnesium oxide				▨ b					▨		▨		
Sodium sulfite				▨ c					▨				
Carbon adsorption				▨					▨	▨	▨	▨	▨
Copper oxide					▨				▨	▨	▨	▨	▨
	1	2	3	4	5	6	7	8	9	10	11	12	13

[a] Gas or oil

[b] Used to calcine

[c] Only if sulfur is to be produced

Figure 7. Example selection matrix for an existing seacoast plant with limited area and 15 years remaining life, burning 1% sulfur coal.

CRITERIA				PROCESSES SURVEYED													PROCESSES SELECTED			
				Limestone/sludge	Lime/sludge	Double alkali/sludge	Seawater	Limestone/gypsum	Lime/gypsum	Double alkali/gypsum	Jet bubbling limestone	Magnesium oxide	Sodium sulfite	Carbon adsorption	Copper oxide	Owner's Weighting (0-10)				
	DEFINITION	RATING 'R' 1 2 3 4		'R' VALUES												'W'	'R' x 'W'			
System status & needs	Number installed	Few	Many	4	4	2	1	4	4	3	3	2	3	1	1					
	Sizes installed	Small	Large	4	4	2	2	4	4	3	3	2	3	2	1					
	Process controlability	Complex	Simple	3	3	3	4	3	3	3	3	2	2	2	2					
	Mechanical technology	Complex	Simple	3	3	3	4	3	3	3	3	2	3	2	2					
	Average availability	Low	High	2	3	2	4	3	3	3	3	1	3	2	1					
	Maintenance required	High	Low	2	3	3	4	2	3	3	3	2	3	1	1					
	Space (equipment & storage of reagents and solid products	Large	Small	2	2	2	4	2	2	2	2	3	3	3	3					
	Ability to follow load	Poor	Good	3	3	3	4	3	3	3	3	3	3	3	3					
				STATUS SUBTOTAL																
Raw material needs	Absorbent availability	Low	High	2	2	2	2	2	2	2	2	3	3	3	3					
	Fresh water requirements	High	Low	2	2	2	3	2	2	2	3	3	3	4	4					
	Reducing agent	High	Low	4	4	4	4	4	4	4	4	2	3	2	1					
				RAW MATERIAL SUBTOTAL																
Byprod's & needs	Marketable quality	Poor	Good	1	1	1	1	3	3	3	4	4	4	4	4					
	Sludge amount	Large	Small	1	1	1	3	3	3	3	3	4	4	4	4					
	Water treatment requirements	Large	Small	3	3	3	1	2	2	2	3	3	3	4	4					
				BYPRODUCT SUBTOTAL																
Control achievable	SO_2	Low	High	3	3	4	3	3	4	4	3	4	4	2	3					
	Particulates	Low	High	3	3	3	3	3	3	3	3	3	2	3	2					
	NO_x	Low	High	1	1	1	1	1	1	1	2	1	1	3	2					
	Halides	Low	High	4	4	4	3	4	4	4	3	4	4	2	2					
				CONTROL SUBTOTAL																
Energy Needs	Reheat	Yes	No	1	1	1	1	1	1	1	1	1	1	4	4					
	Pump & fan requirements	High	Low	2	3	3	3	2	3	3	3	3	3	2	2					
	Other	High	Low	3	3	3	3	3	3	3	3	2	2	2	2					
				ENERGY SUBTOTAL																
Costs	Capital/installed kW*	High	Low	2	3	2	4	2	3	2	3	1	1	1	1					
	Operating/kWh*	High	Low	3	3	2	4	2	3	2	3	2	2	1	1					
				COST SUBTOTAL																
				GRAND TOTALS																

* See cost section of report.

Figure 8. FGD rating chart.

weight those factors most important at his site. A range of 0 to 10 is suggested although a smaller range can be used. Thus, if a condition is not very important, it is weighted with a 0 or 1 factor. For example, nitrogen oxides (NO_x) control may not be required and would be weighted very low. Conversely, cost factors might be very important and would be weighted with a 9 or 10. In the current study, R factors are assumed constant for all process variations. In reality, however, these factors may vary for a specific process depending on such considerations as type fuel (i.e., coal vs oil), type application (new vs retrofit), or other specific considerations.

System Status

This criterion is based on the number of similar processes in operation and on the general operability of the FGD process. The number and sizes of processes in operation are an indicator of a successful system. The lime and limestone processes are the most widely used and are rated the highest. Conversely, those processes that have been applied on a limited basis are rated lower.

The mechanical technology and process controllability are indicators of process operability. The simpler processes are rated higher than those which involve more complex processing steps. The magnesium oxide and dry processes are rated slightly lower than the wet processes because they have shown poorer performance in these areas.

Average availability relates FGD process operation to boiler operation and is a measure of ability to operate when needed. The magnesium oxide, copper oxide, and carbon adsorption processes are rated low in this area because they have reported poor availabilities.

Maintenance requirements relate largely to design and operation and depend less on the actual type of FGD process. The indicated factors are based on engineering judgements on limited information from operating processes.

Space requirements depend on quantities of raw material required, mechanical equipment size, and the amount of sludge for disposal. Those processes that produce sludge are rated lowest because of the large area needed for storage of the sludge over the life of the power unit. Although regenerable processes require extra mechanical equipment, they are rated higher because they do not require sludge disposal sites.

Raw Materials

This criterion deals with absorbent, water, and reducing fuel availabilities. Those processes, such as the lime- and limestone-based processes, that require absorbent in direct proportion to the SO_2 removal are rated the lowest in this area since they require relatively large amounts of absorbent compared to regenerable processes. Processes that require very little absorbent, such as the regenerable processes, are rated higher. Fresh water is required fairly equally by all of the wet processes. The two dry adsorption processes require very little water.

A reductant such as hydrogen is required by the copper oxide process and reducing fuels are required by those regenerable processes that produce sulfur as a final product or require calcination. These processes are rated lower for that reason.

Byproducts

This criterion relates to the solid and liquid streams produced by the FGD process. If a marketable product is produced, the process is rated higher compared to those which produce no marketable byproduct. Those processes that produce a semimarketable product such as gypsum are rated at an intermediate level. The amount of sludge produced is also significant in rating FGD processes. Those processes that produce large amounts of sludge are rated lower and those that produce little or no sludge are rated higher.

Waste water treatment requirements vary widely depending on the local regulations and the specific site conditions. However, all of the wet processes have some type of effluent discharge although the quantity varies depending on the particular FGD process. The dry processes which require no waste water treatment are rated the highest in this area.

Control Efficiency

The ability of an FGD process to achieve high SO_2 removal efficiency is also an important rating criterion. The actual efficiency achieved is most affected by the process design; almost any process can be designed for high control efficiency. Those processes that are rated the highest are reported to more easily achieve high SO_x control efficiency. Particulate control is frequently performed in separate equipment such as an electrostatic precipitator (ESP) or scrubber ahead of the FGD system. However, the FGD process can also remove some particulate matter and are rated fairly evenly in this regard.

NO_x controls are reported to be effective only in the dilute sulfuric acid process, which is no longer offered commercially, and the two dry processes. NO_x removal by the other scrubbing processes has not been well documented but is apparently marginal.

The ability to control other gaseous emissions such as chlorides and fluorides must occasionally also be considered in selecting an FGD process. The wet processes can apparently reduce these compounds more effectively than the dry systems.

Energy Needs

This important criterion is most affected by the reheat required, high pressure drop through the system, and other miscellaneous needs such as high liquid to gas ratios and extensive sludge-handling systems. Reheat is generally required by the wet-scrubbing processes and these are rated lower. The two dry processes do not require reheat and are rated the highest. Pressure drop is again largely a function of design and can vary widely from system to system with the same FGD process. Other large energy needs are not generally required by the wet-scrubbing processes that produce sludge. However, the regenerable processes require additional pumping and product recovery equipment and are thus rated somewhat lower because of additional energy needs. The two dry processes also require additional energy for regeneration. Wide differences in requirements are not apparent.

Costs

System cost is generally one of the most important rating criterion. The economic evaluation section of this report details the costs for individual systems. The ratings reflect these estimated costs. The lime, limestone, and seawater processes are rated higher because they generally cost less to install. Regenerable process installed costs tend to be higher than nonregenerable process costs, but sale of the byproduct can somewhat reduce the operating cost. The following criteria were used to rate process cost:

'R' value	Installed cost range, $/kW	Operating cost, mills/kWh
1	>120	>6
2	100-120	5-6
3	80-100	4-5
4	<80	<4

To utilize the rating system, the weighting factor is multiplied by the rating factor for the selected FGD process. The resulting products are added and the totals are compared with one another. The highest value indicates which process best meets the user's needs.

The examples previously used are also applied here to illustrate the use of the rating chart. Figure 9 rates the four FGD processes selected from the matrix approach. Weighting factors that emphasize high efficiency and availability are chosen and each product of R times W is calculated and summed. Total ratings for the lime gypsum, magnesium oxide, and sodium sulfite processes are 487, 405, and 453 respectively. Because the lime gypsum system has been widely used for oil-fired installations, it scores highest in the system status and needs area.

Figure 10 presents the rating for example No. 2, the coal-fired seacoast plant. The weighting factors emphasize minimum space and cost requirements. In this case, the seawater process scores highest and is followed by the jet-bubbling limestone, double-alkali, and limestone gypsum processes.

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CRITERIA				PROCESSES SURVEYED													PROCESSES SELECTED			
				Limestone/sludge	Lime/sludge	Double alkali/sludge	Seawater	Limestone/gypsum	Lime/gypsum	Double alkali/gypsum	Jet bubbling limestone	Magnesium oxide	Sodium sulfite	Carbon adsorption	Copper oxide	Owner's Weighting (0-10)	Lime/gypsum	Magnesium oxide	Sodium sulfite	
	DEFINITION	RATING 'R' 1 2 3	4	'R' VALUES												'W'	'R' x 'W'			
System status & needs	Number installed	Few	Many	4	4	2	1	4	4	3	3	2	3	1	1	9	36	18	27	
	Sizes installed	Small	Large	4	4	2	2	4	4	3	3	2	3	2	1	9	36	18	27	
	Process controlability	Complex	Simple	3	3	3	4	3	3	3	3	2	2	2	2	6	18	12	12	
	Mecnanical technology	Complex	Simple	3	3	3	4	3	3	3	3	2	3	2	2	7	21	14	21	
	Average availability	Low	High	2	3	2	4	3	3	3	3	1	3	2	1	10	30	10	30	
	Maintenance required	High	Low	2	3	3	4	2	3	3	3	2	3	1	1	5	15	10	15	
	Space (equipment & storage of reagents and solid products	Large	Small	2	2	2	4	2	2	2	2	3	3	3	3	3	6	9	9	
	Ability to follow load	Poor	Good	3	3	3	4	3	3	3	3	3	3	3	3	5	15	15	15	
	STATUS SUBTOTAL																177	106	156	
Raw material needs	Absorbent availability	Low	High	2	2	2	2	2	2	2	2	3	3	3	3	8	16	24	24	
	Fresh water requirements	High	Low	2	2	2	3	2	2	2	3	3	3	4	4	5	10	15	15	
	Reducing agent	High	Low	4	4	4	4	4	4	4	4	2	3	2	1	8	32	16	24	
	RAW MATERIAL SUBTOTAL																58	55	63	
Byprod's & needs	Marketable quality	Poor	Good	1	1	1	1	3	3	3	4	4	4	4	4	9	27	36	36	
	Sludge amount	Large	Small	1	1	1	3	3	3	3	3	4	4	4	4	5	15	20	20	
	Water treatment requirements	Large	Small	3	3	3	1	2	2	2	3	3	3	4	4	9	18	27	27	
	BYPRODUCT SUBTOTAL																60	83	83	
Control achievable	SO_2	Low	High	3	3	4	3	3	4	4	3	4	4	2	3	10	40	40	40	
	Particulates	Low	High	3	3	3	3	3	3	3	3	3	2	3	2	10	30	30	20	
	NO_x	Low	High	1	1	1	1	1	1	1	2	1	1	3	2	8	8	8	8	
	Halides	Low	High	4	4	4	3	4	4	4	3	4	4	2	2	5	20	20	20	
	CONTROL SUBTOTAL																98	98	88	
Energy Needs	Reheat	Yes	No	1	1	1	1	1	1	1	1	1	1	4	4	7	7	7	7	
	Pump & fan requirements	High	Low	2	3	3	3	2	3	3	3	3	3	2	2	7	21	21	21	
	Other	High	Low	3	3	3	3	3	3	3	3	2	2	2	2	5	15	10	10	
	ENERGY SUBTOTAL																43	38	38	
Costs	Capital/installed kW*	High	Low	2	3	2	4	2	3	2	3	1	1	1	1	9	27	9	9	
	Operating/kWh*	High	Low	3	3	2	4	2	3	2	3	2	2	1	1	8	24	16	16	
	COST SUBTOTAL																51	25	25	
	GRAND TOTALS																487	405	457	

* See cost section of report.

Figure 9. Process applicability rating chart applied to example No. 1.

CRITERIA				PROCESSES SURVEYED													PROCESSES SELECTED			
				Limestone/sludge	Lime/sludge	Double alkali/sludge	Seawater	Limestone/gypsum	Lime/gypsum	Double alkali/gypsum	Jet bubbling limestone	Magnesium oxide	Sodium sulfite	Carbon adsorption	Copper oxide	Owner's Weighting (0-10)	Seawater	Limestone/gypsum	Double alkali/gypsum	Jet bubbling limestone
	DEFINITION	RATING 'R' 1 2 3	4	'R' VALUES												'W'	'R' x 'W'			
System status & needs	Number installed	Few	Many	4	4	2	1	4	4	3	3	2	3	1	1	5	5	20	15	15
	Sizes installed	Small	Large	4	4	2	2	4	4	3	3	2	3	2	1	5	10	20	15	15
	Process controlability	Complex	Simple	3	3	3	4	3	3	3	3	2	2	2	2	7	28	21	21	21
	Mechanical technology	Complex	Simple	3	3	3	4	3	3	3	3	2	3	2	2	7	28	21	21	21
	Average availability	Low	High	2	3	2	4	3	3	3	3	1	3	2	1	8	32	24	24	24
	Maintenance required	High	Low	2	3	3	4	2	3	3	3	2	3	1	1	8	32	16	24	24
	Space (equipment & storage of reagents and solid products	Large	Small	2	2	2	4	2	2	2	2	3	3	3	3	10	40	20	20	20
	Ability to follow load	Poor	Good	3	3	3	4	3	3	3	3	3	3	3	3	8	32	24	24	24
	STATUS SUBTOTAL																207	166	164	164
Raw material needs	Absorbent availability	Low	High	2	2	2	2	2	2	2	2	3	3	3	3	9	18	18	18	18
	Fresh water requirements	High	Low	2	2	2	3	2	2	2	3	3	3	4	4	5	15	10	10	15
	Reducing agent	High	Low	4	4	4	4	4	4	4	4	2	3	2	1	10	40	40	40	40
	RAW MATERIAL SUBTOTAL																73	68	68	73
Byprod's & needs	Marketable quality	Poor	Good	1	1	1	1	3	3	3	4	4	4	4	4	0	0	0	0	0
	Sludge amount	Large	Small	1	1	1	3	3	3	3	3	4	4	4	4	10	30	30	30	30
	Water treatment requirements	Large	Small	3	3	3	1	2	2	2	3	3	3	4	4	5	5	10	10	15
	BYPRODUCT SUBTOTAL																35	40	40	45
Control achievable	SO_2	Low	High	3	3	4	3	3	4	4	3	4	4	2	3	8	24	24	32	24
	Particulates	Low	High	3	3	3	3	3	3	3	3	3	2	3	2	8	24	24	24	24
	NO_x	Low	High	1	1	1	1	1	1	1	2	1	1	3	2	5	5	5	5	10
	Halides	Low	High	4	4	4	3	4	4	4	3	4	4	2	2	2	6	8	8	6
	CONTROL SUBTOTAL																59	61	69	64
Energy Needs	Reheat	Yes	No	1	1	1	1	1	1	1	1	1	1	4	4	8	8	8	8	8
	Pump & fan requirements	High	Low	2	3	3	3	2	3	3	3	3	3	2	2	8	24	16	24	24
	Other	High	Low	3	3	3	3	3	3	3	3	2	2	2	2	5	15	15	15	15
	ENERGY SUBTOTAL																47	39	47	47
Costs	Capital/installed kW*	High	Low	2	3	2	4	2	3	2	3	1	1	1	1	10	40	20	20	30
	Operating/kWh*	High	Low	3	3	2	4	2	3	2	3	2	2	1	1	7	28	14	14	21
	COST SUBTOTAL																68	34	34	51
	GRAND TOTALS																489	408	422	444

* See cost section of report.

Figure 10. Process applicability rating chart applied to example No. 2.

SUPPLIERS OF FGD SYSTEMS

Information on FGD systems can be obtained from a number of sources. Suppliers of FGD systems in the United States are shown in Table 18. Direct contacts with these people can be made to obtain further detailed information on their system.

TABLE 18 SUPPLIERS OF FGD SYSTEMS IN THE UNITED STATES

Vendor	Process(es) offered	Contact	Telephone
ACL/Combustion Equipment Associates	Double alkali, lime-alkaline fly ash, sodium carbonate	C. R. Lamantia (A. D. Little) R. S. Sommer (CEA)	(617) 864-5778 (212) 980-3700
Air Correction Division, UOP	Lime, lime-limestone, limestone, sodium carbonate	John Jurek	(312) 391-2000
American Air Filter	Lime	Alex Siako	(502) 632-0469
Babcock & Wilcox	Lime, limestone	Jack Stewart	(216) 753-4511
Buell/Envirotech	Double alkali	W. W. Hanberg (Envirotech)	(412) 264-6682
Chemico	Lime, lime-limestone, limestone	Joseph Maurer	(212) 239-7799
Combustion Engineering	Lime, lime-limestone, limestone, limestone-alkaline fly ash	A. J. Snider	(203) 688-1911
Davy McKee Lakeland, Inc.	Wellman-Lord Lime-gypsum (Saarberg-Holter)	J. Gordon Cavanagh	(813) 646-7514
FMC Corporation	Double alkali	John Reeney	(312) 893-1800
Mitsubishi International	Limestone	Gordon MacDonald	(212) 922-3700
Peabody Engineering	Lime-alkaline fly ash, limestone	T. H. Newhams	(213) 327-7000
Pullman Kellogg	Lime, limestone	David Boem	(201) 646-1000
Research Cottrell	Limestone	James McCarthy	(201) 685-4000
Riley Stoker/Environeering	Limestone	Art Kinch (R.S.) G. Hangshou Cheag (Environeering)	(617) 852-7100 (312) 671-6300
United Engineers	Magnesium oxide	Keith Choper	(617) 338-6000

(continued)

TABLE 18 (continued)

Vendor	Process(es) offered	Contact	Telephone
Wheelebrator-Frye/Atomics International	Aqueous carbonate	John H. Phelan (Wheelebrator) Frye) D. C. Gehri (A.I.)	(412) 288-7301 (213) 341-1000
Chiyoda International Corporation	Jet-bubbling limestone	Donald Clasen	(206) 624-9350
Shell/UOP	Copper oxide	J. D. Pohlenz	(312) 391-2558
Bergbau Forschung (Essen, Germany)	Carbon adsorption	Karl Knoblauch	(0201) 10-59-225
Rockwell International	Aqueous carbonate	D. C. Gehri	(213) 341-1000
Nord Westdeutche Kraftwerk AG	Lime sludge Bischoff process	Wilhelm Bosselmann	Hamburg 2283-493
A/S Norsk Viftefabrikk (Oslo, Norway)	Seawater	Arvid Tokerud	190600

Other important contacts:	Telephone:
H. W. Elder Division of Energy Demonstrations and Technology Office of Power Tennessee Valley Authority Muscle Shoals, Alabama 35660	(205) 386-2514
G. A. Hollinden Division of Energy Demonstrations and Technology Office of Power Tennessee Valley Authority Chattanooga, Tennessee 37401	(615) 755-3584
Jumpei Ando Chu University 1-13-27, Kasuga Bunkyo-Ku Tokyo 112, JAPAN	

REFERENCES

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3. Stephenson, C. D., and R. L. Torstrick. Shawnee Lime/Limestone Scrubbing Computerized Design/Cost-Estimate Model Users Manual. Bull. ECDP B-3, Tennessee Valley Authority, Muscle Shoals, Ala., USA, and EPA-600/7-79-210, U.S. Environmental Protection Agency, Washington, D.C., 1979.

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EPA-600/2-75-006, U.S. Environmental Protection Agency, Washington, D.C., 1975. [Lime, limestone, magnesium oxide, and sodium sulfite processes are included in this study.]

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APPENDIX A

LIMESTONE SLUDGE PROCESS

PROCESS DESCRIPTION

The limestone slurry process, shown in Figure A-1, is designed to use a mobile-bed absorber, with presaturator and mist eliminator. The mist eliminator is equipped for upstream and downstream wash with fresh makeup water. The flue gas from the common plenum is cooled in the presaturator, scrubbed with limestone slurry in the absorber, passes through the mist eliminator, and is reheated before being vented to the stack plenum.

Limestone slurry is recirculated through the absorber and an external surge tank. The slurry is maintained at 15% solids by withdrawal of a purge stream and addition of fresh slurry. The reaction of SO_2 with $CaCO_3$ in the limestone is assumed to produce 80% calcium sulfite hemihydrate ($CaSO_3 \cdot 1/2H_2O$) and 20% gypsum ($CaSO_4 \cdot 2H_2O$). The purge stream containing these salts, unreacted limestone, and minor impurities is pumped one mile to an earthen-diked, clay-lined pond where it settles to a sludge of about 40% solids. Supernate water is returned from the pond for reuse in the process.

The feed preparation area consists of two trains of crushers and wet ball mills serving all four absorber trains. As-received 40 mm maximum-size crushed limestone is further reduced in crushers and processed in wet ball mills to a 60% solids slurry with a particle size of about 70% less than 0.003 mm that is metered to the scrubber slurry loop.

The base-case material balance is shown in Table A-1 and the base-case equipment list is shown in Table A-2. The cost factor for scaling is shown for each area in the equipment list.

SPECIFIC PROCESS PREMISES

1. The flue gas is assumed to be cooled from 149° to 53°C (300° to 127°F) in the presaturator at an L/G ratio of 0.5 liter/m^3 (4 gal/10^3 aft^3).
2. The absorber is a mobile-bed type (TCA) with a flue gas superficial velocity of 3.8 m/sec (12.5 ft/sec) and a pressure drop, including the mist eliminator, of 2.14 kPa (8.6 inches H_2O). An L/G ratio of 6.7 liters/m^3 (50 gal/10^3 aft^3).
3. Stoichiometry is 1.4 moles of $CaCO_3$ to 1.0 mole of SO_2 removed and 1.0 mole of $CaCO_3$ to 2.0 moles of HCl removed.

ENERGY REQUIREMENTS

For base-case conditions, reheat of the cleaned gas from 53°C to 79°C requires 42.2×10^3 kg/hr (93,050 lb/hr) of 243°C (470°F) steam at 3.55×10^3 kPa absolute pressure (500 psig) equivalent to about 17.62×10^6 kcal/hr.

The electrical power demand for the base-case limestone sludge process is about 7,995 kW or 1.6% of the rated output of a 500-MW power plant. For 6,000 hours of operation, the annual electrical energy consumption is 48.0×10^6 kWh.

The total equivalent energy consumption for the base case is approximately 37.7×10^6 kcal/hr or 3.3% of the input energy required for the 500-MW power unit. Summarized energy requirements for all cases are listed in Table A-3.

BYPRODUCT MANAGEMENT

ESP units remove 99.2% of the fly ash from the flue gas and, therefore, only a small amount of fly ash is found in the FGD process sludge. (Fly ash emission from oil-fired units does not exceed the EPA particulate emission standard and fly ash collection facilities are not included in oil-fired power plant design.) Projected mass flow rates of wastes for the base case are shown below.

Component	kg/hr	lb/hr
$CaSO_3 \cdot 1/2H_2O$	16,550	36,480
$CaSO_4 \cdot 2H_2O$	5,670	12,500
$CaCO_3$	6,448	14,215
$CaCl_2$	433	955
Mg	39	85
Fly ash	149	329
Inerts	1,236	2,726
	30,525	67,290

Based on a 30-year life for both the power unit and the FGD units, the sludge disposal pond for the base case requires approximately 123 ha (305 acres). It is designed for an optimum depth of approximately 6.1 m (20 ft). Pond size is listed by case in Table A-4.

ECONOMIC EVALUATION

Capital investment and annual revenue requirement summaries for the base case, five fuel variations, and three power plant size variations are shown in Tables A-5 and A-6. The detailed results are shown in Tables A-7 through A-24. The same results showing the range of estimated accuracies are shown graphically in Figures A-2 and A-3. The effect of fuel sulfur content on costs is shown in Figure A-4.

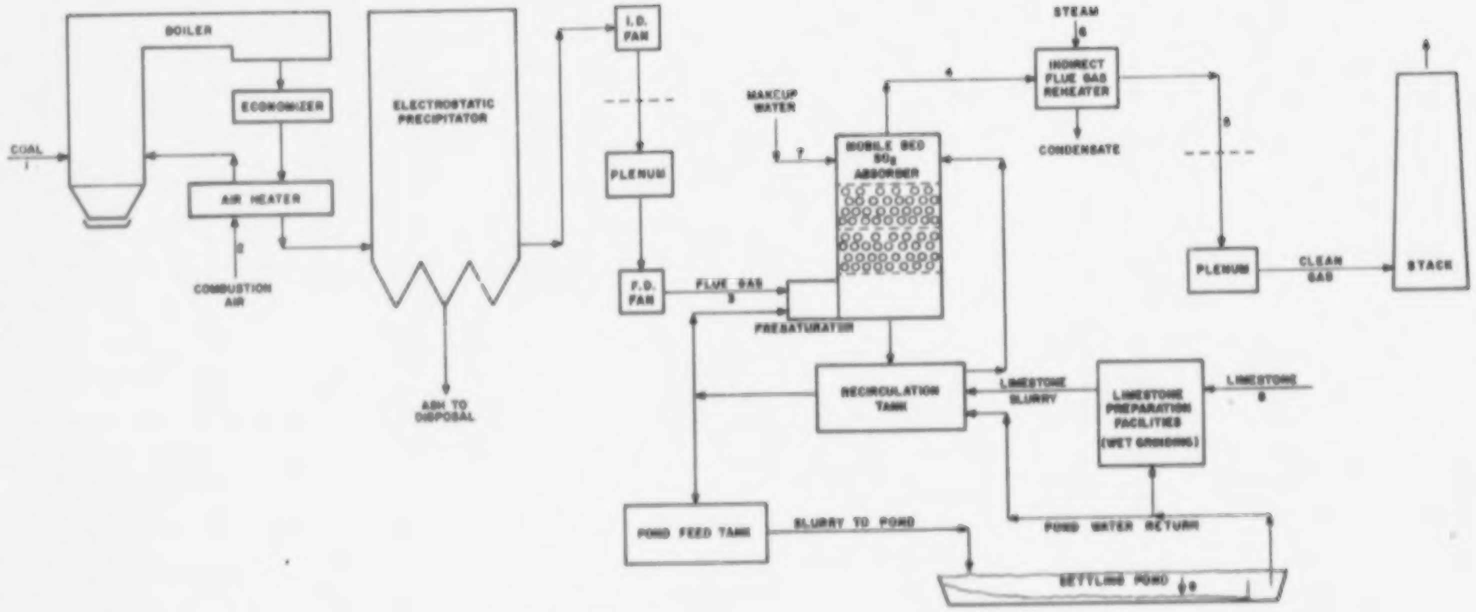
BOILER
COAL
1
ECONOMIZER
AIR HEATER
2
COMBUSTION AIR
ELECTROSTATIC PRECIPITATOR
ASH TO DISPOSAL
I.D. FAN
PLENUM
F.D. FAN
FLUE GAS
3
PRESATURATOR
MAKEUP WATER
7
MOBILE BED SO2 ABSORBER
4
STEAM
6
INDIRECT FLUE GAS REHEATER
CONDENSATE
5
PLENUM
CLEAN GAS
STACK
RECIRCULATION TANK
LIMESTONE SLURRY
LIMESTONE PREPARATION FACILITIES (WET GRINDING)
LIMESTONE
8
POND FEED TANK
SLURRY TO POND
POND WATER RETURN
SETTLING POND
9

Figure A-1. Limestone sludge process flow diagram.

TABLE A-1. LIMESTONE SLUDGE PROCESS

MATERIAL BALANCE - BASE CASE (3.5% SULFUR COAL)

	Stream No.	1	2	3	4	5
	Description	Coal to boiler	Combustion air to air heater	Gas to presaturator-absorber	Gas to reheater	Gas to stack
1	Total stream, 1000 kg/hr	194	2,062	2,225	2,316	2,316
2	Total stream, lb/hr	428,600	4,546,200	4,906,000	5,106,900	5,106,900
3	Gas flow, Nm^3/hr (0°C)		1,615,700	1,697,700	1,182,100	1,815,000
4	Gas flow, aft^3/min (60°F)		1,005,000	1,056,000	1,127,200	1,128,900
5	Liquid flow, liters/min				38.6	
6	Liquid flow, gal/min				10.2	
7	Temperature, °C		27	149	53	79
8	Particulates, kg/hr			199.1	49.8	49.8
9	Particulates, lb/hr			439	110	110
10						

	Stream No.	6	7	8	9	
	Description	Steam to reheater	Makeup water to absorber	Limestone to preparation facilities	Settled sludge	
1	Total stream, 1000 kg/hr	42	141	26	75	
2	Total stream, lb/hr	93,050	310,400	56,240	165,590	
3	Liquid flow, liters/min		2,347		949	
4	Liquid flow, gal/min		620		251	
5	Temperature, °C	263				
6	Pressure, kPa (abs)	3,550				
7	Pressure, psig	500				
8	Specific gravity				1.32	
9	Undissolved solids, %				40	
10						

1						
2						
3						
4						
5						
6						
7						
8						
9						
10						

1						
2						
3						
4						
5						
6						
7						
8						
9						
10						

TABLE A-2. LIMESTONE SLUDGE PROCESS

BASE-CASE EQUIPMENT LIST
DESCRIPTION AND COST

Area 1--Materials Handling			Area size-cost exponent 0.73	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Car shaker	1	Top mounting with crane	9,000	2,100
2. Car puller	1	25 hp with 5 hp return	50,000	2,100
3. Hopper, limestone unloading	1	12 ft x 20 ft x 2 ft bottom, 20 ft deep, 4,800 ft^3, carbon steel	9,300	8,700
4. Feeder, limestone unloading	1	Vibrating pan, 42 in. wide x 60 in. long, 3 hp, 250 tons/hr	4,800	1,100
5. Conveyor, limestone unloading	1	Belt, 36 in. wide x 10 ft long, 5 hp, 250 tons/hr, 130 ft/min	2,200	1,000
6. Conveyor, limestone stocking (incline)	1	Belt, 36 in. wide x 320 ft long, 30 hp, 15° slope, 250 tons/hr, 130 ft/min	48,000	15,400
7. Conveyor, limestone stocking	1	Belt, 36 in. wide x 200 ft long, 7-1/2 hp, 250 tons/hr, 130 ft/min	30,000	10,100
8. Tripper	1	1 hp, 30 ft/min	14,800	2,800
9. Mobile equipment	1	Scraper tractor, 22 to 24 yd^3 capacity	181,000	-
10. Hopper, reclaim	2	7 ft x 7 ft, 4 ft deep, 60° slope, carbon steel	10,700	1,900
11. Feeder, live limestone storage	2	Vibrating pan, 24 in. wide x 40 in. long, 1 hp, 15 tons/hr	7,000	2,100
12. Pump, tunnel sump	2	Vertical, 60 gpm, 70 ft head, 5 hp, carbon steel, neoprene lined, (1 operating, 1 spare)	6,800	1,600

(continued)

TABLE A-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
13. Conveyor, live limestone feed	1	Belt, 30 in. wide x 100 ft long, 2 hp, 100 tons/hr, 60 ft/min	14,400	5,100
14. Conveyor, live limestone feed (incline)	1	Belt, 30 in. wide x 190 ft long, 5 hp, 35 ft lift, 100 tons/hr, 60 ft/min	26,600	9,900
15. Elevator, live limestone feed	1	Continuous, bucket 12 in. x 8 in. x 11-3/4 in., 20 hp, 75 ft lift, 100 tons/hr, 160 ft/min	30,800	1,800
16. Bin, crusher feed	2	13 ft dia x 21 ft high, with cover, 3/8 in. carbon steel	10,900	15,700
17. Dust collecting system	1	Cyclone, 2,100 aft^3/min, motor-driven fan	5,900	4,800
18. Dust collecting system	1	Cyclone, 6,200 aft^3/min, motor-driven fan	14,200	11,100
19. Dust collecting system	1	Bag filter, polypropylene bag, 14,400 aft^3/min, automatic shaker system (1/2 cost in feed preparation area)	12,000	28,200
Subtotal			488,400	125,500

Area 2--Feed Preparation

Area size-cost exponent 0.70

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Discharge, feeder bin	2	Vibrating, 15 tons/hr, carbon steel	19,500	4,200
2. Feeder, crusher	2	Weigh belt, 18 in. wide x 14 ft long, 2 hp, 15 tons/hr	15,800	2,000
3. Crusher	2	Gyratory, 0 x 1-1/2 to 3/4 in., 75 hp, 15 tons/hr	107,500	11,900

(continued)

TABLE A-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
4. Ball mill	2	Wet, open system, 8 ft dia x 13 ft long, 350 hp, 340 tons/day	424,500	35,200
Ball charge			31,100	-
5. Hoist	1	Electric, 5 ton, 7-1/2 in.	8,300	2,100
6. Tank, milled product	1	7-1/2 ft dia x 7-1/2 ft high, 2,440 gal, open top, four 7-1/2-in. baffles, agitator supports, carbon steel (20 min residence time)	1,300	2,200
Lining		1/4 in. neoprene lining	1,300	1,600
7. Agitator, milled product tank	1	36 in. dia, 10 hp, neoprene coated	12,000	1,200
8. Pump, milled product tank	2	Centrifugal, 116 gpm, 60 ft head, 7-1/2 hp, carbon steel, neoprene lined (1 operating, 1 spare)	5,400	1,500
9. Tank, slurry feed	1	21-1/2 ft dia x 22 ft high, 58,600 gal, open top, four 21-1/2-in.-baffles, agitator supports, carbon steel (8 hr residence time)	10,500	18,500
Lining		1/4 in. neoprene lining	10,700	13,100
10. Agitator, slurry feed tank	1	Two turbines, 84 in. dia, 75 hp, neoprene coated	58,000	6,000
11. Pump, slurry feed tank	2	Centrifugal, 116 gpm, 60 ft head, 7-1/2 hp, carbon steel, neoprene lined (1 operating, 1 spare)	5,400	1,500
12. Dust collecting system	1	Cyclone, 8,200 aft^3/min, motor-driven fan	16,300	12,700

(continued)

TABLE A-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
13. Dust collecting system	1	Bag filter, polypropylene bag, 14,400 aft^3/min, automatic shaker system (1/2 cost in materials handling area)	12,000	28,200
Subtotal			739,600	141,900

Area 3--Gas Handling			Area size-cost exponent 0.68	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Fans	4	Forced draft, 14.8 in. static head, 875 rpm, 1,200 hp, fluid drive, double width, double inlet	1,427,900	93,100
Subtotal			1,427,900	93,100

Area 4--SO_2 Absorption			Area size-cost exponent 0.74	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. SO_2 absorber	4	TCA scrubber, 31 ft long x 14 ft wide x 40 ft high, 1/4 in. carbon steel, neoprene lining, 316 SS grids, nitrile foam spheres, FRP spray headers, 316 SS chevron vane entrainment separator	2,813,700	242,300
2. Tank, recirculation	4	32 ft dia x 32 ft high, 192,500 gal, open top, four 32 in. wide baffles, agitator supports, carbon steel (10 min residence time)	92,200	169,000

(continued)

TABLE A-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
2. (continued)				
Lining		1/4 in. neoprene lining	93,100	113,800
3. Agitator, recirculation tank	4	132 in. dia, 60 hp, neoprene coated	220,000	81,800
4. Pump, presaturator	6	Centrifugal, 1,274 gpm, 60 ft head, 50 hp, carbon steel, neoprene lined (4 operating, 2 spare)	48,900	11,200
5. Pump, slurry recirculation	10	Centrifugal, 7,954 gpm, 100 ft head, 500 hp, carbon steel, neoprene lined (8 operating, 2 spare)	442,800	39,100
6. Pump, makeup water	2	Centrifugal, 1,240 gpm, 200 ft head, 150 hp, carbon steel (1 operating, 1 spare)	33,200	7,900
7. Soot blowers	40	Air, retractable	260,000	225,800
Subtotal			4,003,900	890,900

Area 5--Reheat

Area size-cost exponent 0.75

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Reheater	4	Steam, tube type, 3,665 ft^2, one-half of tubes made of Inconel 625 and one-half made of Cor-Ten	856,000	39,200
2. Soot blowers	20	Air, retractable	130,000	112,900
Subtotal			986,000	152,100

(continued)

TABLE A-2 (continued)

Area 6--Solids Disposal				Area size-cost exponent 0.54	
	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1.	Tank, pond feed	1	*16 ft dia x 32 ft high, 48,100 gal, open top, four 16 in. baffles, agitator supports, carbon steel	10,100	19,200
	Lining		1/4 in. neoprene lining	10,700	13,000
2.	Agitator, pond feed tank	1	Two turbines, 60 in. dia, 5 hp, neoprene coated	9,000	900
3.	Pump, pond feed	2	Centrifugal, 803 gpm, 150 ft head, 75 hp, carbon steel, neoprene lined (1 operating, 1 spare)	27,200	7,700
4.	Pump, pond return	2	Centrifugal, 552 gpm, 150 ft head, 50 hp, carbon steel (1 operating, 1 spare)	23,000	6,300
	Subtotal			80,000	47,100

*Size of pond feed tank not a function of residence time.

TABLE A-3. LIMESTONE SLUDGE PROCESS ENERGY REQUIREMENTS

Case	Reheat, kcal/hr	Electricity, kcal/hr (kW)	Process steam, kcal/hr	Oil, kcal/hr	Natural gas, kcal/hr	Total equivalent energy consumption, % of input energy
200-MW unit[a]						
Coal, 3.5% sulfur	7.21 M	7.72 M (3,328)	-	-	-	3.39
500-MW unit[b]						
Coal, 3.5% sulfur (base case)	17.62 M	18.13 M (7,995)	-	-	-	3.33
Coal, 0.8% sulfur	18.06 M	16.98 M (7,485)	-	-	-	3.27
Coal, 1.4% sulfur	17.45 M	16.66 M (7,345)	-	-	-	3.18
Coal, 2.0% sulfur	17.53 M	17.14 M (7,558)	-	-	-	3.23
Lignite, 0.5% sulfur	18.52 M	17.27 M (7,614)	-	-	-	3.34
Oil, 2.5% sulfur	14.67 M	14.40 M (6,350)	-	-	-	2.56
700-MW unit[c]						
Coal, 3.5% sulfur	24.39 M	24.74 M (11,029)	-	-	-	3.30
1000-MW unit[d]						
Coal, 3.5% sulfur	34.07 M	33.68 M (15,363)	-	-	-	3.26

---

a. Based on a boiler efficiency of 90% for generation of steam and a gross heat rate of 2,318 kcal/kWh (9,200 Btu/kWh) for generation of electricity.

b. Based on a boiler efficiency of 90% for generation of steam and a gross heat rate of 2,268 kcal/kWh (9,000 Btu/kWh) for generation of electricity.

c. Based on a boiler efficiency of 90% for generation of steam and a gross heat rate of 2,243 kcal/kWh (8,900 Btu/kWh) for generation of electricity.

d. Based on a boiler efficiency of 90% for generation of steam and a gross heat rate of 2,192 kcal/kWh (8,700 Btu/kWh) for generation of electricity.

TABLE A-4. LIMESTONE SLUDGE PROCESS POND SIZE

Case	Area, hectares	(acres)	Depth, meters	(ft)
200-MW unit				
Coal, 3.5% sulfur	61	(150)	5.2	(17)
500-MW unit				
Coal, 3.5% sulfur (base case)	123	(305)	6.1	(20)
Coal, 0.8% sulfur	39	(96)	4.6	(15)
Coal, 1.4% sulfur	52	(128)	4.9	(16)
Coal, 2.0% sulfur	75	(185)	5.4	(18)
Lignite, 0.5% sulfur	30	(74)	4.6	(15)
Oil, 2.5% sulfur	66	(163)	5.2	(17)
700-MW unit				
Coal, 3.5% sulfur	159	(394)	6.4	(21)
1000-MW unit				
Coal, 3.5% sulfur	209	(516)	6.9	(23)

TABLE A-5. LIMESTONE SLUDGE PROCESS CAPITAL INVESTMENT

Case	Total capital investment $	Total capital investment $/kW
200-MW unit		
Coal, 3.5% sulfur	26,302,000	132
500-MW unit		
Coal, 3.5% sulfur (base case)	53,083,000	106
Coal, 0.8% sulfur	39,995,000	80
Coal, 1.4% sulfur	41,634,000	83
Coal, 2.0% sulfur	45,511,000	91
Lignite, 0.5% sulfur	39,036,000	78
Oil, 2.5% sulfur	40,637,000	81
700-MW unit		
Coal, 3.5% sulfur	70,967,000	101
1000-MW unit		
Coal, 3.5% sulfur	93,941,000	94

TABLE A-6. LIMESTONE SLUDGE PROCESS ANNUAL REVENUE REQUIREMENTS

Case	$	Mills/kWh	$/ton coal (bbl oil) burned	$/MBtu heat input	$/ton sulfur removed
200-MW unit					
Coal, 3.5% sulfur	7,029,100	5.86	13.37	0.64	501
500-MW unit					
Coal, 3.5% sulfur (base case)	14,638,000	4.88	11.39	0.54	429
Coal, 0.8% sulfur	11,151,700	3.72	7.85	0.41	1,397
Coal, 1.4% sulfur	11,539,200	3.85	10.77	0.43	973
Coal, 2.0% sulfur	12,573,100	4.19	10.24	0.47	669
Lignite, 0.5% sulfur	10,945,400	3.65	6.41	0.41	1,883
Oil, 2.5% sulfur	11,384,500	3.79	(2.55)	0.42	710
700-MW unit					
Coal, 3.5% sulfur	19,734,300	4.70	11.09	0.53	415
1000-MW unit					
Coal, 3.5% sulfur	26,384,700	4.40	10.61	0.51	397

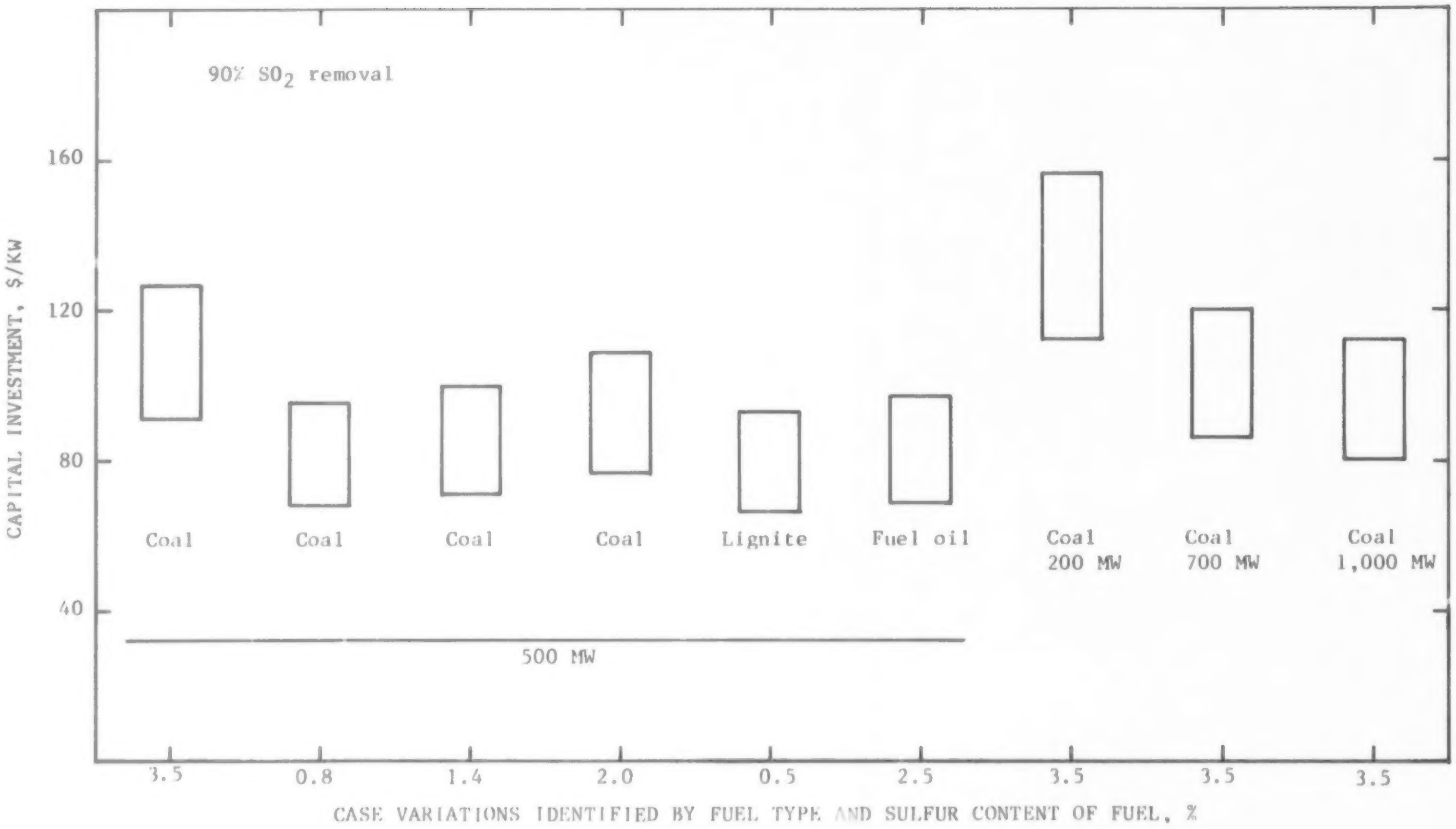

Figure A-2. Limestone sludge process capital investment range.

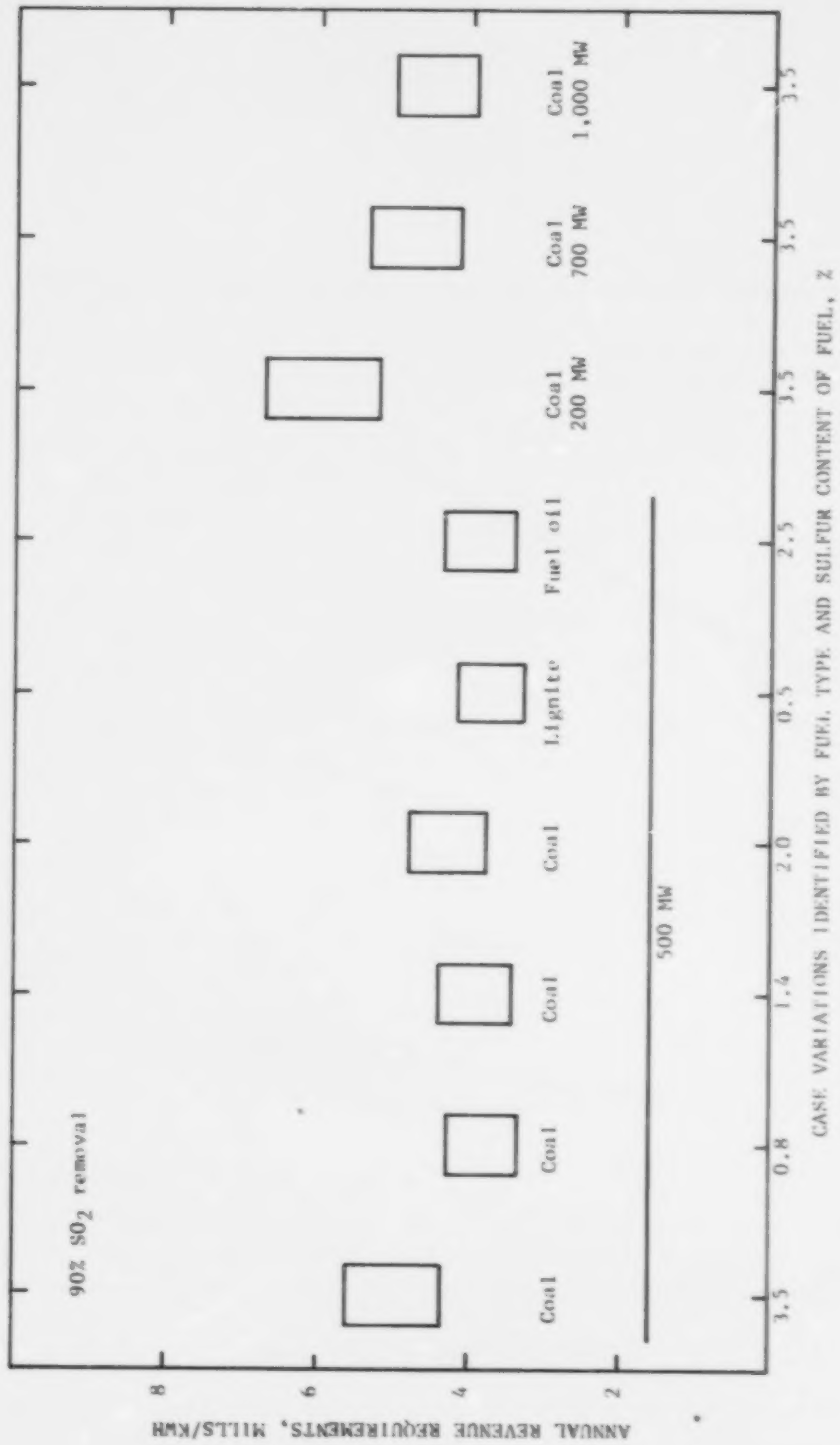

Figure A-3. Limestone sludge process annual revenue requirement range.

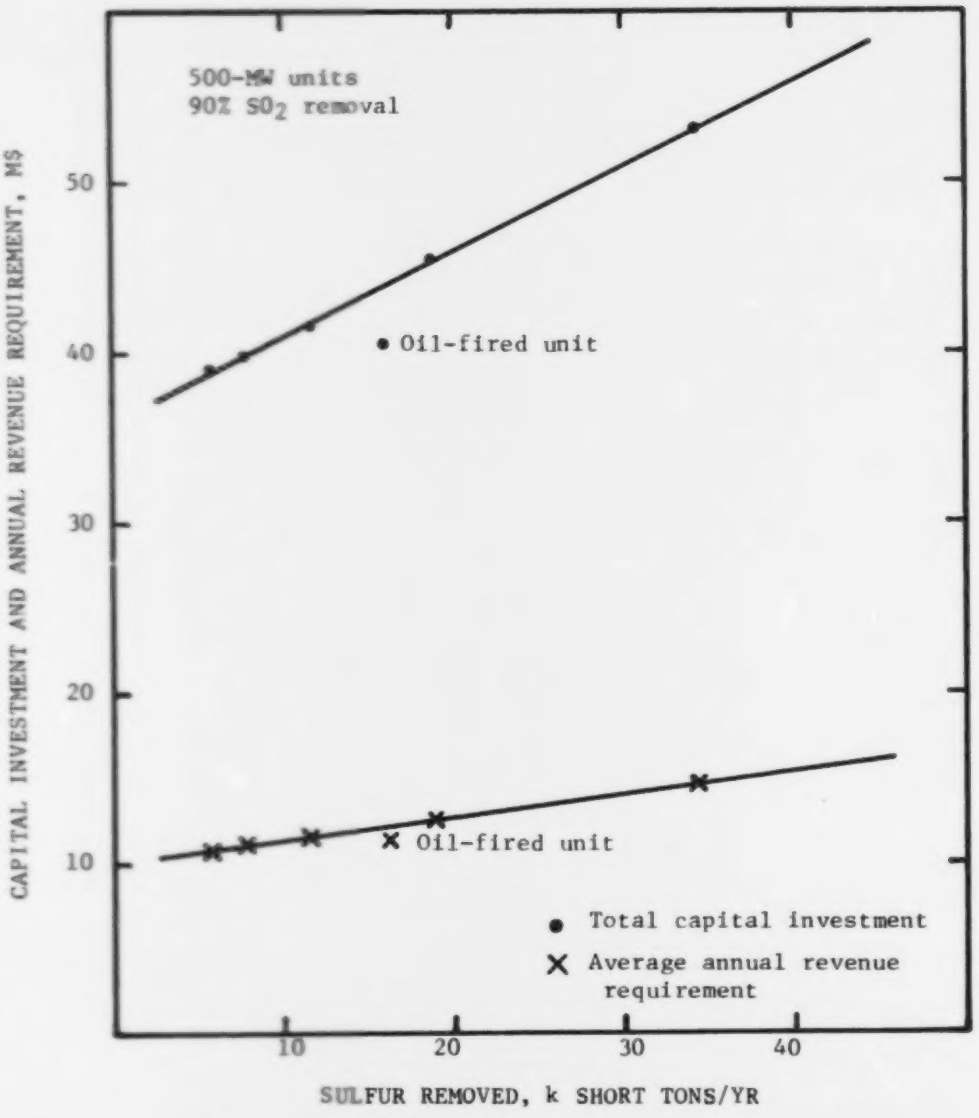

Figure A-4. Limestone sludge process. Effect of sulfur removed on capital investment and annual revenue requirements.

TABLE A-7. LIMESTONE SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	1,824,000	6.4
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	2,062,000	7.2
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,950,000	17.3
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,458,000	33.2
Stack gas reheat (four indirect steam reheaters)	1,292,000	4.5
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	2,164,000	7.6
Subtotal	21,750,000	76.2
Services, utilities, and miscellaneous	1,305,000	4.6
Total process areas excluding pond construction	23,055,000	80.8
Pond construction	5,481,000	19.2
Total direct investment	28,536,000	100.0
Indirect Investment		
Engineering design and supervision	1,240,000	4.3
Architect and engineering contractor	274,000	1.0
Construction expense	3,915,000	13.7
Contractor fees	1,226,000	4.3
Total indirect investment	6,655,000	23.3
Contingency	7,038,000	24.7
Total fixed investment	42,229,000	148.0
Other Capital Charges		
Allowance for startup and modifications	3,675,000	12.9
Interest during construction	5,068,000	17.7
Total depreciable investment	50,972,000	178.6
Land	1,098,000	3.9
Working capital	1,013,000	3.5
Total capital investment	53,083,000	186.0

Basis
- Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
- Stack gas reheat to 79°C (175°F).
- Minimum in-process storage; only pumps are spared.
- Disposal pond located 1 mi from power plant.
- Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
- Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-8. LIMESTONE SLUDGE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	168,700 tons	7.00/ton	1,180,900	8.07
Total raw materials cost			1,180,900	8.07
Conversion costs				
Operating labor and supervision	24,060 man-hr	12.50/man-hr	300,800	2.06
Utilities				
Steam	419,600 MBtu	2.00/MBtu	839,200	5.73
Process water	223,300 kgal	0.12/kgal	26,800	0.18
Electricity	47,967,300 kWh	0.029/kWh	1,391,100	9.50
Maintenance				
Labor and material			2,008,800	13.73
Analyses	3,220 man-hr	17.00/man-hr	54,700	0.37
Total conversion costs			4,621,400	31.57
Total direct costs			5,802,300	39.64
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,058,300	20.89
Average cost of capital and taxes at 8.6% of total capital investment			4,565,100	31.19
Overheads				
Plant, 50% of conversion costs less utilities			1,182,200	8.08
Administrative, 10% of operating labor			30,100	0.20
Total indirect costs			8,835,700	60.36
Total annual revenue requirements			14,638,000	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	4.88	11.39	0.54	429

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,166,221 metric tons/yr (1,285,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 30,947 metric tons/yr (34,120 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $28,536,000; total depreciable investment, $50,972,000; and total capital investment, $53,083,000.
All tons shown are 2,000 lb.

TABLE A-9. LIMESTONE SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 0.8% S in coal; 90% SO_2 removal; pond disposal of waste solids)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	631,000	3.0
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	746,000	3.5
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	5,034,000	23.8
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,628,000	45.4
Stack gas reheat (four indirect steam reheaters)	1,315,000	6.2
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	987,000	4.7
Subtotal	18,341,000	86.6
Services, utilities, and miscellaneous	1,101,000	5.2
Total process areas excluding pond construction	19,442,000	91.8
Pond construction	1,748,000	8.2
Total direct investment	21,190,000	100.0
Indirect Investment		
Engineering design and supervision	1,112,000	5.3
Architect and engineering contractor	262,000	1.2
Construction expense	3,142,000	14.8
Contractor fees	978,000	4.6
Total indirect investment	5,494,000	25.9
Contingency	5,337,000	25.2
Total fixed investment	32,021,000	151.1
Other Capital Charges		
Allowance for startup and modifications	3,027,000	14.3
Interest during construction	3,843,000	18.1
Total depreciable investment	38,891,000	183.5
Land	364,000	1.7
Working capital	740,000	3.5
Total capital investment	39,995,000	188.7

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-10. LIMESTONE SLUDGE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 0.8% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	39,400 tons	7.00/ton	275,800	2.47
Total raw materials cost			275,800	2.47
Conversion costs				
Operating labor and supervision	24,060 man-hr	12.50/man-hr	300,800	2.69
Utilities				
Steam	429,900 MBtu	2.00/MBtu	859,800	7.71
Process water	109,400 kgal	0.12/kgal	13,100	0.12
Electricity	44,911,500 kWh	0.029/kWh	1,302,400	11.68
Maintenance				
Labor and material			1,607,800	14.42
Analyses	1,350 man-hr	17.00/man-hr	23,000	0.21
Total conversion costs			4,106,900	36.83
Total direct costs			4,382,700	39.30
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,333,500	20.93
Average cost of capital and taxes at 8.6% of total capital investment			3,439,600	30.84
Overheads				
Plant, 50% of conversion costs less utilities			965,800	8.66
Administrative, 10% of operating labor			30,100	0.27
Total indirect costs			6,769,000	60.70
Total annual revenue requirements			11,151,700	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	3.72	7.85	0.41	1,397

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,288,938 metric tons/yr (1,421,100 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 7,238 metric tons/yr (7,980 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $21,190,000; total depreciable investment, $38,891,000; and total capital investment, $39,995,000.
All tons shown are 2,000 lb.

TABLE A-11. LIMESTONE SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 1.4% S in coal; 90% SO_2 removal; pond disposal of waste solids)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	843,000	3.8
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	984,000	4.5
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,915,000	22.2
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,392,000	42.5
Stack gas reheat (four indirect steam reheaters)	1,283,000	5.8
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,223,000	5.5
Subtotal	18,640,000	84.3
Services, utilities, and miscellaneous	1,118,000	5.1
Total process areas excluding pond construction	19,758,000	89.4
Pond construction	2,342,000	10.6
Total direct investment	22,100,000	100.0
Indirect Investment		
Engineering design and supervision	1,136,000	5.1
Architect and engineering contractor	264,000	1.2
Construction expense	3,238,000	14.7
Contractor fees	1,009,000	4.6
Total indirect investment	5,647,000	25.6
Contingency	5,549,000	25.1
Total fixed investment	33,296,000	150.7
Other Capital Charges		
Allowance for startup and modifications	3,095,000	14.0
Interest during construction	3,996,000	18.0
Total depreciable investment	40,387,000	182.7
Land	478,000	2.2
Working capital	769,000	3.5
Total capital investment	41,634,000	188.4

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-12. LIMESTONE SLUDGE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 1.4% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	58,600 tons	7.00/ton	410,200	3.55
Total raw materials cost			410,200	3.55
Conversion costs				
Operating labor and supervision	24,060 man-hr	12.50/man-hr	300,800	2.61
Utilities				
Steam	415,500 MBtu	2.00/MBtu	831,000	7.20
Process water	124,000 kgal	0.12/kgal	14,900	0.13
Electricity	44,071,000 kWh	0.029/kWh	1,278,100	11.08
Maintenance				
Labor and material			1,650,900	14.31
Analyses	1,710 man-hr	17.00/man-hr	29,100	0.25
Total conversion costs			4,104,800	35.58
Total direct costs			4,515,000	39.13
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,423,200	21.00
Average cost of capital and taxes at 8.6% of total capital investment			3,580,500	31.03
Overheads				
Plant, 50% of conversion costs less utilities			990,400	8.58
Administrative, 10% of operating labor			30,100	0.26
Total indirect costs			7,024,200	60.87
Total annual revenue requirements			11,539,200	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	3.85	10.77	0.43	973

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 971,941 metric tons/yr (1,071,600 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 10,748 metric tons/yr (11,850 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $22,100,000; total depreciable investment, $40,387,000; and total capital investment, $41,634,000.
All tons shown are 2,000 lb.

TABLE A-13. LIMESTONE SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 2.0% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	1,180,000	4.9
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	1,359,000	5.6
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,930,000	20.3
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,420,000	38.7
Stack gas reheat (four indirect steam reheaters)	1,287,000	5.3
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,569,000	6.5
Subtotal	19,745,000	81.3
Services, utilities, and miscellaneous	1,185,000	4.9
Total process areas excluding pond construction	20,930,000	86.2
Pond construction	3,346,000	13.8
Total direct investment	24,276,000	100.0
Indirect Investment		
Engineering design and supervision	1,173,000	4.8
Architect and engineering contractor	268,000	1.1
Construction expense	3,474,000	14.3
Contractor fees	1,084,000	4.5
Total indirect investment	5,999,000	24.7
Contingency	6,055,000	24.9
Total fixed investment	36,330,000	149.6
Other Capital Charges		
Allowance for startup and modifications	3,298,000	13.6
Interest during construction	4,360,000	18.0
Total depreciable investment	43,988,000	181.2
Land	675,000	2.8
Working capital	848,000	3.5
Total capital investment	45,511,000	187.5

Basis
Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-14. LIMESTONE SLUDGE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 2.0% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	92,900 tons	7.00/ton	650,300	5.17
Total raw materials cost			650,300	5.17
Conversion costs				
Operating labor and supervision	24,060 man-hr	12.50/man-hr	300,800	2.39
Utilities				
Steam	417,400 MBtu	2.00/MBtu	834,800	6.64
Process water	155,100 kgal	0.12/kgal	18,600	0.15
Electricity	45,350,500 kWh	0.029/kWh	1,315,200	10.47
Maintenance				
Labor and material			1,774,800	14.11
Analyses	2,250 man-hr	17.00/man-hr	38,300	0.30
Total conversion costs			4,282,500	34.06
Total direct costs			4,932,800	39.23
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,639,300	20.99
Average cost of capital and taxes at 8.6% of total capital investment			3,913,900	31.13
Overheads				
Plant, 50% of conversion costs less utilities			1,057,000	8.41
Administrative, 10% of operating labor			30,100	0.24
Total indirect costs			7,640,300	60.77
Total annual revenue requirements			12,573,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	4.19	10.24	0.47	669

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,113,161 metric tons/yr (1,227,300 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 17,043 metric tons/yr (18,790 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $24,276,000; total depreciable investment, $43,988,000; and total capital investment, $45,511,000.
All tons shown are 2,000 lb.

TABLE A-15. LIMESTONE SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new lignite-fired power unit, 0.5% S in lignite;
90% SO_2 removal; pond disposal of waste solids)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	502,000	2.4
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	598,000	2.9
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	5,118,000	24.8
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,817,000	47.5
Stack gas reheat (four indirect steam reheaters)	1,341,000	6.5
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	831,000	4.0
Subtotal	18,207,000	88.1
Services, utilities, and miscellaneous	1,092,000	5.3
Total process areas excluding pond construction	19,299,000	93.4
Pond construction	1,365,000	6.6
Total direct investment	20,664,000	100.0
Indirect Investment		
Engineering design and supervision	1,096,000	5.3
Architect and engineering contractor	260,000	1.3
Construction expense	3,085,000	14.9
Contractor fees	959,000	4.6
Total indirect investment	5,400,000	26.1
Contingency	5,213,000	25.2
Total fixed investment	31,277,000	151.3
Other Capital Charges		
Allowance for startup and modifications	2,991,000	14.5
Interest during construction	3,753,000	18.2
Total depreciable investment	38,021,000	184.0
Land	289,000	1.4
Working capital	726,000	3.5
Total capital investment	39,036,000	188.9

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-16. LIMESTONE SLUDGE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new lignite-fired power unit, 0.5% S in lignite;
90% SO_2 removal; pond disposal of waste solids)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	28,700 tons	7.00/ton	200,900	1.84
Total raw materials cost			200,900	1.84
Conversion costs				
Operating labor and supervision	24,060 man-hr	12.50/man-hr	300,800	2.75
Utilities				
Steam	441,000 MBtu	2.00/MBtu	882,000	8.06
Process water	101,700 kgal	0.12/kgal	12,200	0.11
Electricity	45,686,400 kWh	0.029/kWh	1,324,900	12.10
Maintenance				
Labor and material			1,584,900	14.48
Analyses	1,110 man-hr	17.00/man-hr	18,900	0.17
Total conversion costs			4,123,700	37.67
Total direct costs			4,324,600	39.51
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,281,300	20.84
Average cost of capital and taxes at 8.6% of total capital investment			3,357,100	30.67
Overheads				
Plant, 50% of conversion costs less utilities			952,300	8.70
Administrative, 10% of operating labor			30,100	0.28
Total indirect costs			6,620,800	60.49
Total annual revenue requirements			10,945,400	100.00

	Mills/kWh	$/ton lignite burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	3.65	6.41	0.41	1,883

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Lignite burned, 1,549,900 metric tons/yr (1,708,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 5,270 metric tons/yr (5,810 tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $20,664,000; total depreciable investment, $38,021,000; and total capital investment, $39,036,000.
All tons shown are 2,000 lb.

TABLE A-17. LIMESTONE SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new oil-fired power unit, 2.5% S in oil;
90% SO_2 removal; pond disposal of waste solids)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	1,051,000	4.9
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	1,215,000	5.7
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,371,000	20.3
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	8,257,000	38.5
Stack gas reheat (four direct oil-fired reheaters)	1,127,000	5.2
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,439,000	6.7
Subtotal	17,460,000	81.3
Services, utilities, and miscellaneous	1,048,000	4.9
Total process areas excluding pond construction	18,508,000	86.2
Pond construction	2,961,000	13.8
Total direct investment	21,469,000	100.0
Indirect Investment		
Engineering design and supervision	1,159,000	5.4
Architect and engineering contractor	266,000	1.2
Construction expense	3,138,000	14.6
Contractor fees	987,000	4.6
Total indirect investment	5,550,000	25.8
Contingency	5,404,000	25.2
Total fixed investment	32,423,000	151.0
Other Capital Charges		
Allowance for startup and modifications	2,946,000	13.7
Interest during construction	3,891,000	18.2
Total depreciable investment	39,260,000	182.9
Land	600,000	2.8
Working capital	777,000	3.6
Total capital investment	40,637,000	189.3

Basis
- Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
- Stack gas reheat to 79°C (175°F) by direct oil-fired reheat.
- Minimum in-process storage; only pumps are spared.
- Disposal pond located 1 mi from power plant.
- Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
- Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-18. LIMESTONE SLUDGE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new oil-fired power unit, 2.5% S in oil;
90% SO_2 removal; pond disposal of waste solids)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	79,200 tons	7.00/ton	554,400	4.87
Total raw materials cost			554,400	4.87
Conversion costs				
Operating labor and supervision	24,060 man-hr	12.50/man-hr	300,800	2.64
Utilities				
Fuel oil (No. 6)	2,425,900 gal	0.40/gal	970,400	8.52
Process water	131,100 kgal	0.12/kgal	15,700	0.14
Electricity	38,099,900 kWh	0.029/kWh	1,104,900	9.70
Maintenance				
Labor and material			1,570,000	13.79
Analyses	2,050 man-hr	17.00/man-hr	34,900	0.31
Total conversion costs			3,996,700	35.10
Total direct costs			4,551,100	39.97
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,355,600	20.69
Average cost of capital and taxes at 8.6% of total capital investment			3,494,800	30.71
Overheads				
Plant, 50% of conversion costs less utilities			952,900	8.37
Administrative, 10% of operating labor			30,100	0.26
Total indirect costs			6,833,400	60.03
Total annual revenue requirements			11,384,500	100.00

	Mills/kWh	$/bbl oil burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	3.79	2.55	0.42	710

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Oil burned, 710 x 10^6 liters/yr (4,464,300 bbl/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
S removed, 14,530 metric tons/yr (16,020 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $21,469,000; total depreciable investment, $39,260,000; and total capital investment, $40,637,000.
All tons shown are 2,000 lb.

TABLE A-19. LIMESTONE SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(200-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	950,000	7.0
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	1,103,000	8.2
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	2,158,000	16.0
SO_2 absorption (two TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	4,076,000	30.2
Stack gas reheat (two indirect steam reheaters)	556,000	4.1
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,335,000	9.9
Subtotal	10,178,000	75.4
Services, utilities, and miscellaneous	611,000	4.5
Total process areas excluding pond construction	10,789,000	79.9
Pond construction	2,717,000	20.1
Total direct investment	13,506,000	100.0
Indirect Investment		
Engineering design and supervision	943,000	7.0
Architect and engineering contractor	214,000	1.6
Construction expense	2,098,000	15.5
Contractor fees	694,000	5.1
Total indirect investment	3,949,000	29.2
Contingency	3,491,000	25.9
Total fixed investment	20,946,000	155.1
Other Capital Charges		
Allowance for startup and modifications	1,823,000	13.5
Interest during construction	2,514,000	18.6
Total depreciable investment	25,283,000	187.2
Land	554,000	4.1
Working capital	465,000	3.4
Total capital investment	26,302,000	194.7

Basis
- Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
- Stack gas reheat to 79°C (175°F) by indirect steam reheat.
- Minimum in-process storage; only pumps are spared.
- Disposal pond located 1 mi from power plant.
- Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
- Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-20. LIMESTONE SLUDGE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(200-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	69,000 tons	7.00/ton	483,000	6.87
Total raw materials cost			483,000	6.87
Conversion costs				
Operating labor and supervision	16,440 man-hr	12.50/man-hr	205,500	2.92
Utilities				
Steam	171,600 MBtu	2.00/MBtu	343,200	4.88
Process water	91,300 kgal	0.12/kgal	11,000	0.16
Electricity	19,968,500 kWh	0.031/kWh	619,000	8.81
Maintenance				
Labor and material			944,600	13.44
Analyses	1,890 man-hr	17.00/man-hr	32,100	0.46
Total conversion costs			2,155,400	30.67
Total direct costs			2,638,400	37.54
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			1,517,000	21.58
Average cost of capital and taxes at 8.6% of total capital investment			2,262,000	32.18
Overheads				
Plant, 50% of conversion costs less utilities			591,100	8.41
Administrative, 10% of operating labor			20,600	0.29
Total indirect costs			4,390,700	62.46
Total annual revenue requirements			7,029,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	5.86	13.37	0.64	501

Basis
1980 revenue requirements
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 476,810 metric tons/yr (525,700 tons/yr), 2,318 kcal/kWh (9,200 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 12,721 metric tons/yr (14,025 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $13,506,000; total depreciable investment, $25,283,000; and total capital investment, $26,302,000.
All tons shown are 2,000 lb.

TABLE A-21. LIMESTONE SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(700-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, puller)	2,313,000	6.0
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	2,590,000	6.7
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	7,029,000	18.2
SO_2 absorption (six TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	13,374,000	34.7
Stack gas reheat (six indirect steam reheaters)	1,824,000	4.7
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	2,580,000	6.7
Subtotal	29,710,000	77.0
Services, utilities, and miscellaneous	1,783,000	4.6
Total process areas excluding pond construction	31,493,000	81.6
Pond construction	7,100,000	18.4
Total direct investment	38,593,000	100.0
Indirect Investment		
Engineering design and supervision	1,538,000	4.0
Architect and engineering contractor	342,000	0.9
Construction expense	5,041,000	13.0
Contractor fees	1,542,000	4.0
Total indirect investment	8,463,000	21.9
Contingency	9,411,000	24.4
Total fixed investment	56,467,000	146.3
Other Capital Charges		
Allowance for startup and modifications	4,937,000	12.8
Interest during construction	6,776,000	17.6
Total depreciable investment	68,180,000	176.7
Land	1,408,000	3.6
Working capital	1,379,000	3.6
Total capital investment	70,967,000	183.9

Basis
Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-22. LIMESTONE SLUDGE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(700-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	233,600 tons	7.00/ton	1,635,200	8.29
Total raw materials cost			1,635,200	8.29
Conversion costs				
Operating labor and supervision	29,440 man-hr	12.50/man-hr	368,000	1.86
Utilities				
Steam	580,800 MBtu	2.00/MBtu	1,161,600	5.89
Process water	309,100 kgal	0.12/kgal	37,100	0.19
Electricity	66,175,600 kWh	0.029/kWh	1,919,100	9.72
Maintenance				
Labor and material			2,732,400	13.85
Analyses	3,920 man-hr	17.00/man-hr	66,600	0.34
Total conversion costs			6,284,800	31.85
Total direct costs			7,920,000	40.13
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,090,800	20.73
Average cost of capital and taxes at 8.6% of total capital investment			6,103,200	30.93
Overheads				
Plant, 50% of conversion costs less utilities			1,583,500	8.02
Administrative, 10% of operating labor			36,800	0.19
Total indirect costs			11,814,300	59.87
Total annual revenue requirements			19,734,300	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	4.70	11.09	0.53	415

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,614,460 metric tons/yr (1,780,000 tons/yr), 2,243 kcal/kWh (8,900 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 43,064 metric tons/yr (47,480 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $38,593,000; total depreciable investment, $68,180,000; and total capital investment, $70,967,000.
All tons shown are 2,000 lb.

TABLE A-23. LIMESTONE SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(1000-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, puller)	2,951,000	5.7
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	3,270,000	6.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	9,672,000	18.7
SO_2 absorption (eight TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	18,443,000	35.7
Stack gas reheat (eight indirect steam reheaters)	2,519,000	4.9
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	3,090,000	6.0
Subtotal	39,945,000	77.3
Services, utilities, and miscellaneous	2,397,000	4.6
Total process areas excluding pond construction	42,342,000	81.9
Pond construction	9,357,000	18.1
Total direct investment	51,699,000	100.0
Indirect Investment		
Engineering design and supervision	1,814,000	3.5
Architect and engineering contractor	403,000	0.8
Construction expense	6,431,000	12.4
Contractor fees	1,925,000	3.7
Total indirect investment	10,573,000	20.4
Contingency	12,456,000	24.1
Total fixed investment	74,726,000	144.5
Other Capital Charges		
Allowance for startup and modifications	6,537,000	12.6
Interest during construction	8,967,000	17.4
Total depreciable investment	90,230,000	174.5
Land	1,844,000	3.6
Working capital	1,867,000	3.6
Total capital investment	93,941,000	181.7

Basis
Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-24. LIMESTONE SLUDGE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(1000-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	326,200 tons	7.00/ton	2,283,400	8.65
Total raw materials cost			2,283,400	8.65
Conversion costs				
Operating labor and supervision	36,470 man-hr	12.50/man-hr	455,900	1.73
Utilities				
Steam	811,100 MBtu	2.00/MBtu	1,622,200	6.15
Process water	431,700 kgal	0.12/kgal	51,800	0.20
Electricity	92,175,200 kWh	0.028/kWh	2,580,900	9.78
Maintenance				
Labor and material			3,668,100	13.90
Analyses	4,790 man-hr	17.00/man-hr	81,400	0.31
Total conversion costs			8,460,300	32.07
Total direct costs			10,743,700	40.72
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			5,413,800	20.52
Average cost of capital and taxes at 8.6% of total capital investment			8,078,900	30.62
Overheads				
Plant, 50% of conversion costs less utilities			2,102,700	7.97
Administrative, 10% of operating labor			45,600	0.17
Total indirect costs			15,641,000	59.28
Total annual revenue requirements			26,384,700	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	4.40	10.61	0.51	397

Basis
- 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 6,000 hr/yr.
- Coal burned, 2,254,530 metric tons/yr (2,485,700 tons/yr), 2,192 kcal/kWh (8,700 Btu/kWh).
- Stack gas reheat to 79°C (175°F).
- Sulfur removed, 60,134 metric tons/yr (66,300 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $51,699,000; total depreciable investment, $90,230,000; and total capital investment, $93,941,000.
- All tons shown are 2,000 lb.

APPENDIX B

LIME SLUDGE PROCESS

PROCESS DESCRIPTION

Lime slurry scrubbing differs from limestone scrubbing in this study only in the raw material used as SO_2 absorbent and in the method of preparing the scrubbing slurry. The process is shown in Figure B-1.

Pebble lime is slaked in two parallel slakers at a slurry concentration of 60% solids and combined with scrubber effluent slurry and recycle pond water to control the concentration of the recirculating slurry at approximately 15% solids. The flue gas is cooled in a presaturation chamber and passed through a mobile-bed absorber. The lime slurry circulates through the absorber where it reacts with the SO_2 in the cooled flue gas. Mist eliminators equipped for upstream and downstream wash with fresh makeup water control entrainment carryover in the gas stream. A bleedstream from the recirculation tank is pumped to an earthen-diked, clay-lined pond one mile away where it settles to form a sludge containing approximately 40% solids. The sludge is assumed to be 80% $CaSO_3 \cdot 1/2H_2O$ and 20% gypsum. Pond supernate is recycled to the slakers and the absorber recirculation tank to maintain closed-loop operation. Scrubber outlet gas is reheated to 79°C (175°F) by indirect steam heat before entering the stack.

The base-case material balance is shown in Table B-1 and the base-case equipment list is shown in Table B-2.

SPECIFIC PROCESS PREMISES

1. The flue gas is assumed to be cooled from 149°C to 53°C (300°F to 127°F) in the presaturator at an L/G ratio of 0.5 liter/m^3 (4 gal/10^3 aft^3).

2. The absorber is a mobile-bed type with a flue gas superficial velocity of 3.8 m/sec (12.5 ft/sec) and a pressure drop of 2.14 kPa (8.6 in. H_2O), including the mist eliminator. An L/G ratio of 7.4 liters/m^3 (55 gal/10^3 aft^3) is used.

3. Stoichiometry is 1.05 moles of CaO to 1.0 mole of SO_2 removed and 1.0 mole of CaO to 2.0 moles of HCl removed.

ENERGY REQUIREMENTS

For base-case conditions, reheat of the cleaned gas from 53°C to 79°C requires 42.1 x 10^3 kg/hr (92,740 lb/hr) of 243°C (470°F) steam at 3.55 x 10^3 kPa absolute pressure (500 psig), equivalent to about 17.56 x 10^6 kcal/hr.

The electrical power demand for the base-case lime-sludge process is about 7448 kW or 1.5% of the rated output of a 500-MW power plant. For 6000 hours of operation, the annual electrical energy consumption is 44.7 x 10^6 kWh.

The total equivalent energy consumption for the base case is approximately 36.41 x 10^6 kcal/hr or 3.2% of the input energy required for the 500-MW power unit. Summarized energy requirements for all cases are listed in Table B-3.

BYPRODUCT MANAGEMENT

Electrostatic precipitators remove 99.2% of the fly ash from the flue gas and, therefore, only a small amount of fly ash is found in the FGD process sludge. (Fly ash emission from oil-fired units does not exceed the EPA particulate emission standard and fly ash collection facilities are not included in oil-fired power plant design.) Projected mass flow rates of byproduct wastes for the base case are shown below.

Component	Kg/hr	Lb/hr
$CaSO_3 \cdot 1/2H_2O$	16,550	36,480
$CaSO_4 \cdot 2H_2O$	5,670	12,500
$Ca(OH)_2$	451	995
$CaCl_2$	433	955
Mg	123	271
Fly ash	149	329
Inerts	102	225
	23,478	51,755

Based on a 30-year life for both the power unit and the FGD unit, the sludge disposal pond for the base case requires approximately 104 hectares (256 acres). It is designed for an optimum depth of approximately 5.8 meters (19 ft). Pond size is listed by case in Table B-4.

ECONOMIC EVALUATION

Capital investment and annual revenue requirements for the base case and five fuel variations are summarized in Tables B-5 and B-6. The detailed results are shown in Tables B-7 through B-18. The results, including accuracy ranges, are shown graphically in Figures B-2 and B-3. The effect of fuel sulfur content on costs is shown in Figure B-4.

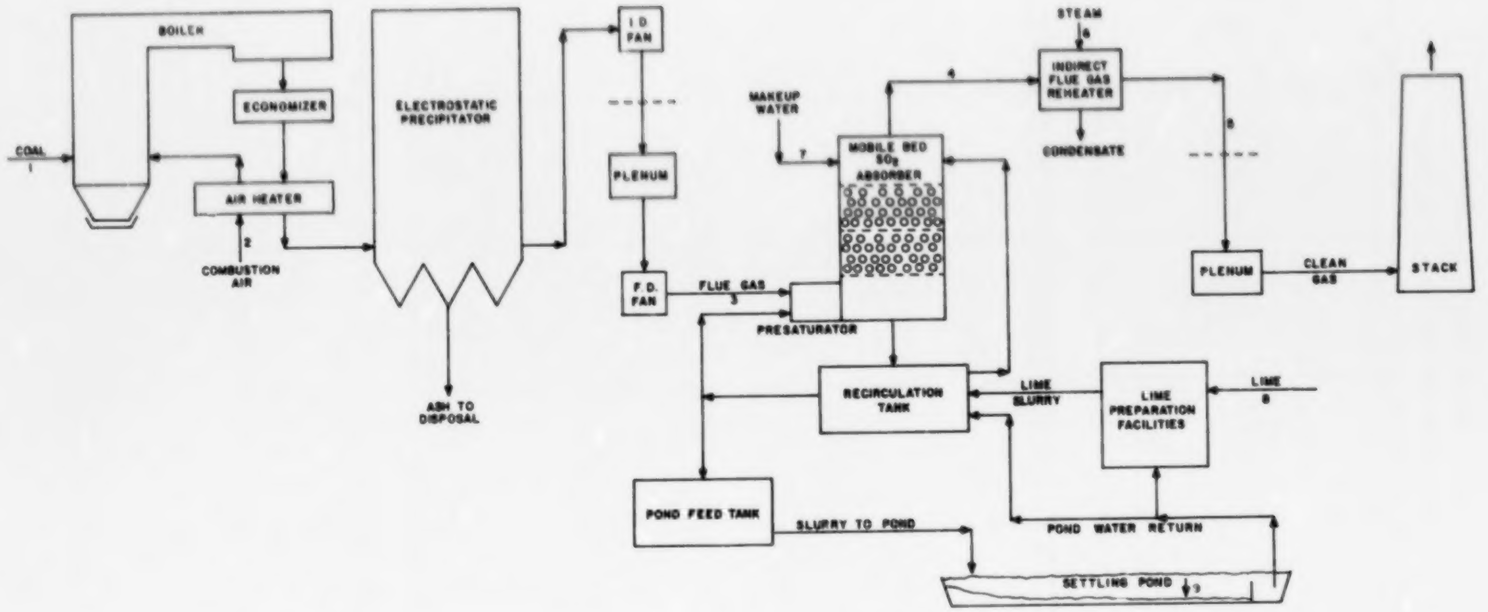
BOILER
COAL
1
ECONOMIZER
AIR HEATER
2
COMBUSTION AIR
ELECTROSTATIC PRECIPITATOR
ASH TO DISPOSAL
I.D. FAN
PLENUM
F.D. FAN
FLUE GAS
3
MAKEUP WATER
7
MOBILE BED SO_2 ABSORBER
PRESATURATOR
4
STEAM
6
INDIRECT FLUE GAS REHEATER
CONDENSATE
5
PLENUM
CLEAN GAS
STACK
RECIRCULATION TANK
LIME SLURRY
LIME PREPARATION FACILITIES
LIME
8
POND FEED TANK
SLURRY TO POND
POND WATER RETURN
SETTLING POND
9

Figure B-1. Lime sludge process flow diagram.

TABLE B-1. LIME SLUDGE PROCESS

MATERIAL BALANCE - BASE CASE (3.5% SULFUR COAL)

	Stream No.	1	2	3	4	5
	Description	Coal to boiler	Combustion air to air heater	Gas to presaturator-absorber	Gas to reheater	Gas to stack
1	Total stream, 1000 kg/hr	194	2,062	2,225	2,307	2,308
2	Total stream, lb/hr	428,600	4,546,200	4,906,000	5,088,000	5,088,000
3	Gas flow, Nm^3/hr (0°C)		1,615,700	1,697,700	1,805,000	1,807,800
4	Gas flow, sft^3/min (60°F		1,005,000	1,056,000	1,122,700	1,124,500
5	Liquid flow, liters/min				38.4	
6	Liquid flow, gal/min				10	
7	Temperature, $^{\circ}$C		27	149	53	79
8	Particulates, kg/hr			199.1	49.8	49.8
9	Particulates, lb/hr			439	110	110
10						

	Stream No.	6	7	8	9	
	Description	Steam to reheater	Makeup water to absorber	Lime to preparation facilities	Settled sludge	
1	Total stream, 1000 kg/hr	42.1	130	10.2	57.3	
2	Total stream, lb/hr	92,740	285,800	22,500	126,300	
3	Liquid flow, liters/min		2,162		730	
4	Liquid flow, gal/min		571		193	
5	Temperature, $^{\circ}$C	243				
6	Pressure, kPa (abs)	3,550 x 10^3				
7	Pressure, psig	500				
8	Specific gravity				1.31	
9	Undissolved solids, %				40	
10						

1						
2						
3						
4						
5						
6						
7						
8						
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10						

1						
2						
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10						

TABLE B-2. LIME SLUDGE PROCESS

BASE-CASE EQUIPMENT LIST
DESCRIPTION AND COST

Area 1--Materials Handling			Area size-cost exponent 0.74	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Conveyor, lime storage (enclosed)	1	Belt, 24 in. wide x 1,500 ft long, 30 hp, 100 tons/hr, 150 ft/min	155,800	52,300
2. Elevator, lime storage	1	Continuous, bucket 16 in. x 8 in. x 11-3/4 in., 75 hp, 120 ft lift, 100 tons/hr, 160 ft/min	102,900	2,400
3. Silo, lime storage	1	50 ft dia x 74 ft straight side, 145,300 ft^3, 60^o slope 3/8 in. carbon steel	88,400	246,100
4. Feeder, reclaim	1	Vibrating pan, 3-1/2 hp, 40 tons/hr	12,200	2,100
5. Conveyor, live lime feed (enclosed)	1	Belt, 18 in. wide x 100 ft long, 2 hp, 40 tons/hr, 100 ft/min	23,400	4,800
6. Elevator, live lime feed	1	Continuous, bucket 11 in. x 6 in. x 8-3/4 in., 50 hp, 50 ft lift, 40 tons/hr, 160 ft/min, with diverter gate	56,000	1,100
7. Bin, lime feed	2	10 ft dia x 15 ft high, w/cover, carbon steel	5,400	11,300
8. Dust collecting system	1	Bag filter, polypropylene bag, 8,800 aft^3/min, 7-1/2 hp, automatic shaker system (1/2 cost in feed preparation area)	10,700	28,200
Subtotal			454,800	348,300

TABLE B-2 (continued)

Area 2--Feed Preparation			Area size-cost exponent 0.57	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Feeder, lime bin discharge	2	Vibrating, 3-1/2 hp	9,200	3,700
2. Feeder, slaker weigh	2	Screw, 12 in. dia x 12 ft long, 1 hp, 6 tons/hr	12,000	1,400
3. Slaker	2	7 ft wide x 31 ft long, 10 hp slaker, 2 hp classifier, 6 tons/hr	116,300	12,100
4. Tank slaker product	2	3-1/2 ft dia x 4 ft high, 288 gal, open top, four 3-1/2 in. baffles, agitator supports, carbon steel, (10 min residence time)	600	1,100
Lining		1/4 in. neoprene lining	700	800
5. Agitator, slaker product tank	2	Two turbines, 14 in. dia, 1-1/2 hp, neoprene coated	7,600	2,200
6. Pump, slaker product tank	3	Centrifugal, 25 gpm, 60 ft head, 2 hp, carbon steel, neoprene lined (2 operating, 1 spare)	5,100	1,800
7. Tank, slurry feed	1	16 ft dia x 17-1/2 ft high, 26,300 gal, open top, four 16 in. baffles, agitator supports, carbon steel, (8 hr residence time)	5,700	10,800
Lining		1/4 in. neoprene lining	6,300	7,700
8. Agitator, slurry feed tank	1	Two turbines, 64 in. dia, 20 hp, neoprene coated	26,100	1,600
9. Pump, slurry feed tank	2	Centrifugal, 50 gpm, 60 ft head, 3 hp, carbon steel, neoprene lined (1 operating, 1 spare)	3,500	1,200

(continued)

TABLE B-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
10. Dust collecting system	1	Bag filter, polypropylene bag, 8,800 aft^3/min, 7-1/2 hp, automatic shaker system (1/2 cost in materials handling area)	10,700	28,200
Subtotal			203,800	72,600

Area 3--Gas Handling

Area size-cost exponent 0.68

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Fans	4	Forced draft, 14.8 in. static head, 875 rpm, 1,200 hp, fluid drive, double width, double inlet	1,427,900	93,100
Subtotal			1,427,900	93,100

Area 4--SO_2 Absorption

Area size-cost exponent 0.74

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. SO_2 absorber	4	TCA scrubber, 31 ft long x 14 ft wide x 40 ft high, 1/4 in. carbon steel, neoprene lining, 316 SS grids, nitrile foam spheres, FRP spray headers, 316 SS chevron vane entrainment separator	2,813,700	252,300
2. Tank, recirculation	4	33 ft dia x 32-1/2 ft high, 207,950 gal, open top, four 33 in. baffles, agitator supports, carbon steel, (10 min residence time)	92,800	177,000
Lining		1/4 in. neoprene lining	97,800	119,600

(continued)

TABLE B-2 (continued)

	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
3.	Agitator, recirculation tank	4	132 in. dia, 60 hp, neoprene coated	220,000	81,800
4.	Pump, presaturator	6	Centrifugal, 1,190 gpm, 60 ft head, 50 hp, carbon steel, neoprene lined (4 operating, 2 spares)	48,900	11,200
5.	Pump, slurry recirculation	10	Centrifugal, 8,710 gpm, 100 ft head, 500 hp, carbon steel, neoprene lined (8 operating, 2 spares)	442,800	39,100
6.	Pump, makeup water	2	Centrifugal, 2,280 gpm, 200 ft head, 250 hp, carbon steel, (1 operating, 1 spare)	49,900	8,800
7.	Soot blowers	40	Air, retractable	260,000	225,800
	Subtotal			4,025,900	915,600

Area 5--Reheat

Area size-cost exponent 0.75

	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1.	Reheater	4	Steam, tube type, 3,600 ft^2 one-half tubes made of Inconel 625 and one-half made of Cor-Ten	856,000	39,200
2.	Soot blowers	20	Air, retractable	130,000	112,900
	Subtotal			986,000	152,100

TABLE B-2 (continued)

Area 6--Solids Disposal			Area size-cost exponent 0.54	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Tank, pond feed	1	*16-1/2 ft dia x 32-1/2 ft high, 51,980 gal, open top, four 16-1/2 in. baffles, agitator supports, carbon steel	10,600	20,200
Lining		1/4 in. neoprene lining	11,200	13,700
2. Agitator, pond feed tank	1	Two turbines, 66 in. dia, 25 hp, neoprene coated	17,800	1,500
3. Pump, pond feed	2	Centrifugal, 610 gpm, 150 ft head, 60 hp, carbon steel, neoprene lined (1 operating, 1 spare)	14,400	3,000
4. Pump, pond return	2	Centrifugal, 420 gpm, 150 ft head, 40 hp, carbon steel (1 operating, 1 spare)	10,500	3,000
Subtotal			64,500	41,400

*Size of pond feed tank not a function of residence time.

TABLE B-3. LIME SLUDGE PROCESS ENERGY REQUIREMENTS

Case	Reheat, kcal/hr	Electricity, kcal/hr, (kW)	Process steam, kcal/hr	Oil, kcal/hr	Natural gas, kcal/hr	Total equivalent energy consumption,[a] % of input energy
500-MW unit						
Coal, 3.5% S (base case)	17.56 M	16.89 M (7,448)	-	-	-	3.21
Coal, 0.8% S	18.00 M	16.82 M (7,416)	-	-	-	3.25
Coal, 1.4% S	17.39 M	16.34 M (7,203)	-	-	-	3.14
Coal, 2.0% S	17.47 M	16.54 M (7,291)	-	-	-	3.17
Lignite, 0.5% S	18.46 M	17.21 M (7,587)	-	-	-	3.33
Oil, 2.5% S	14.62 M	13.88 M (6,121)	-	-	-	2.51

a. Based on boiler efficiency of 90% for generation of steam and a gross heat rate of 9,000 Btu/kWh for generation of electricity.

TABLE B-4. LIME SLUDGE PROCESS POND SIZE

Case	Area hectares	(acres)	Depth meters	(ft)
500-MW unit				
Coal, 3.5% S (base case)	104	(256)	5.8	(19)
Coal, 0.8% S	33	(82)	4.6	(15)
Coal, 1.4% S	45	(110)	4.9	(16)
Coal, 2.0% S	64	(158)	5.2	(17)
Lignite, 0.5% S	26	(64)	4.3	(14)
Oil, 2.5% S	55	(135)	5.2	(17)

TABLE B-5. LIME SLUDGE PROCESS CAPITAL INVESTMENT

Case	Total capital investment $	$/kW
500-MW unit		
Coal, 3.5% S (base case)	47,743,000	96
Coal, 0.8% S	37,795,000	76
Coal, 1.4% S	38,912,000	78
Coal, 2.0% S	41,952,000	84
Lignite, 0.5% S	37,165,000	74
Oil, 2.5% S	37,286,000	75

TABLE B-6. LIME SLUDGE PROCESS ANNUAL REVENUE REQUIREMENTS

Case	$	Mills/kWh	$/ton coal (bbl oil) burned	$/MBtu heat input	$/ton S removed
500-MW unit					
Coal, 3.5% S (base case)	14,972,100	4.99	11.64	0.55	438
Coal, 0.8% S	11,064,200	3.69	7.79	0.41	1,386
Coal, 1.4% S	11,498,200	3.83	10.73	0.43	970
Coal, 2.0% S	12,644,700	4.21	10.30	0.47	672
Lignite, 0.5% S	10,836,300	3.61	6.34	0.40	1,865
Oil, 2.5% S	11,387,700	3.80	(2.55)	0.42	710

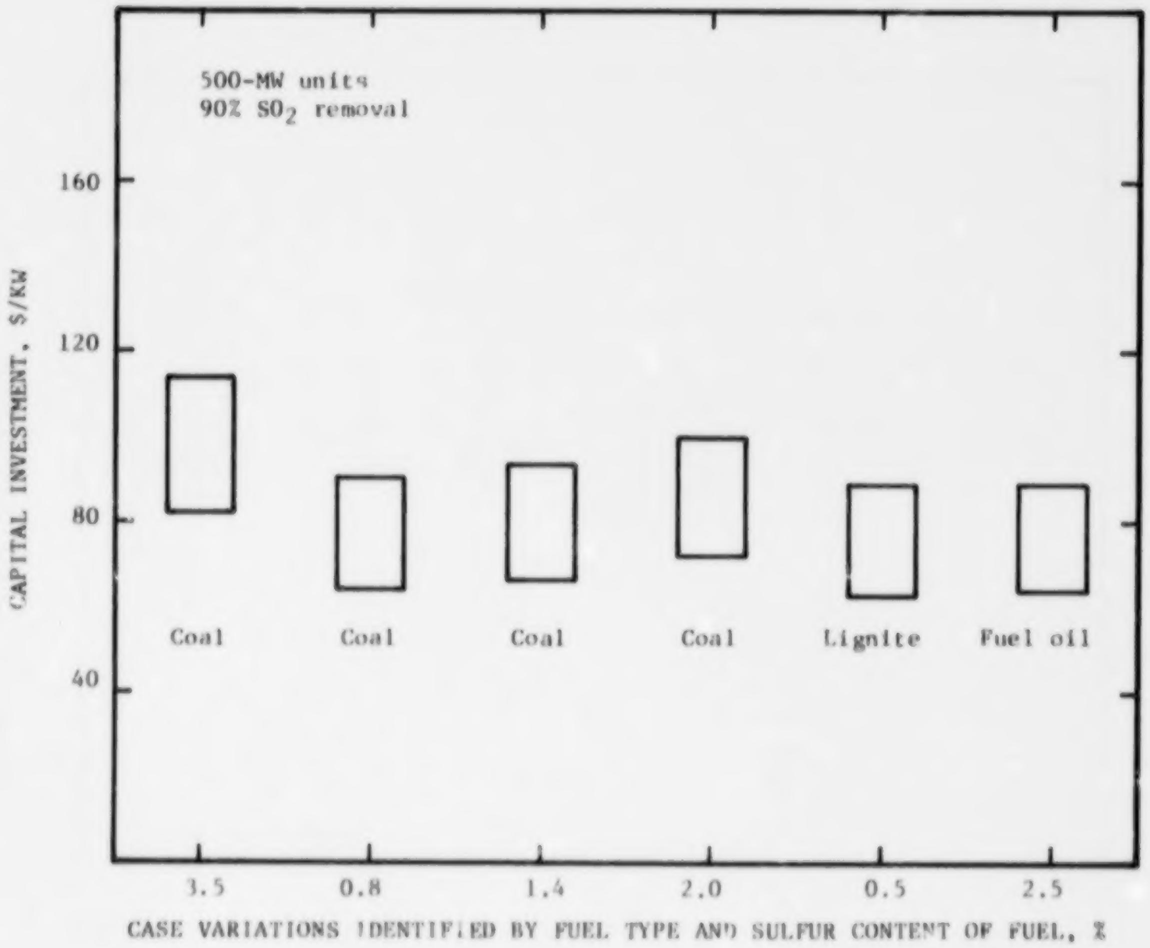

Figure B-2. Lime sludge process capital investment range.

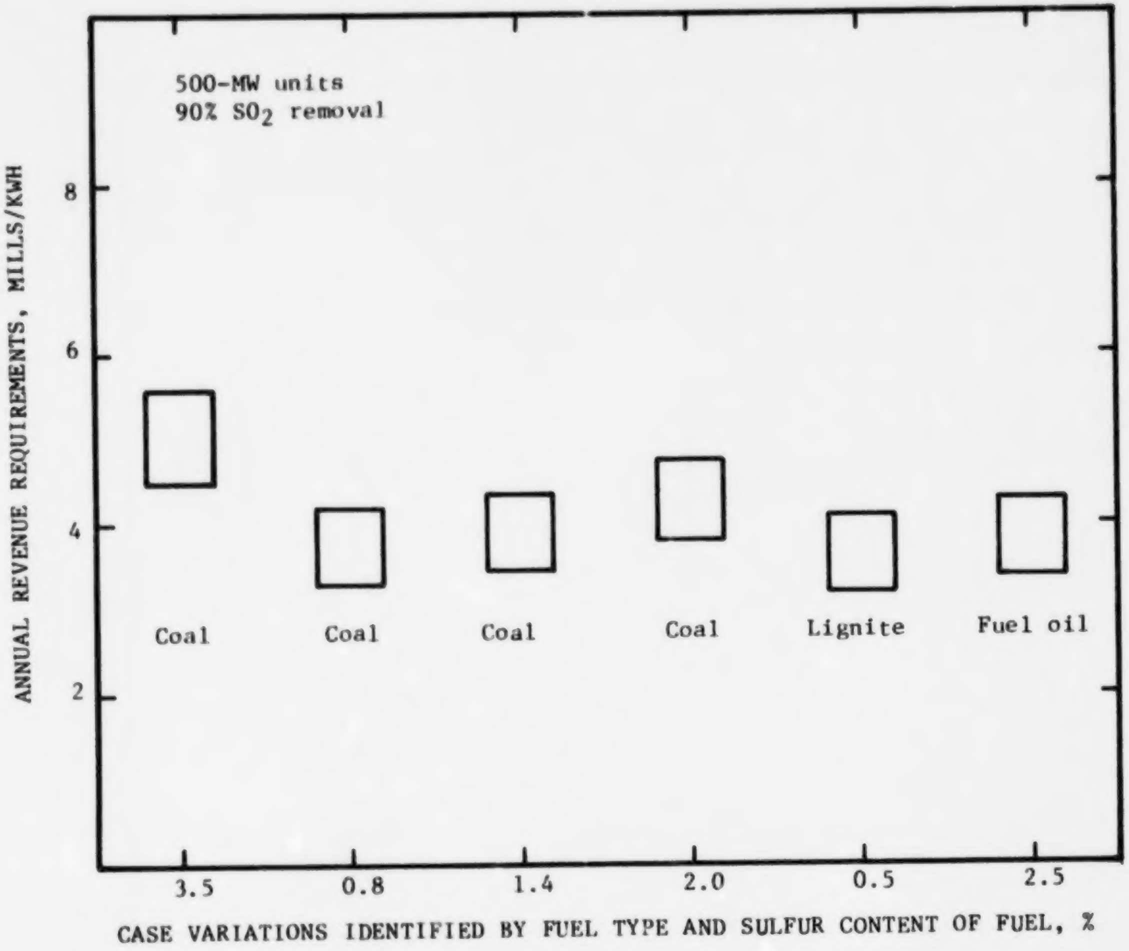

Figure B-3. Lime sludge process annual revenue requirement range.

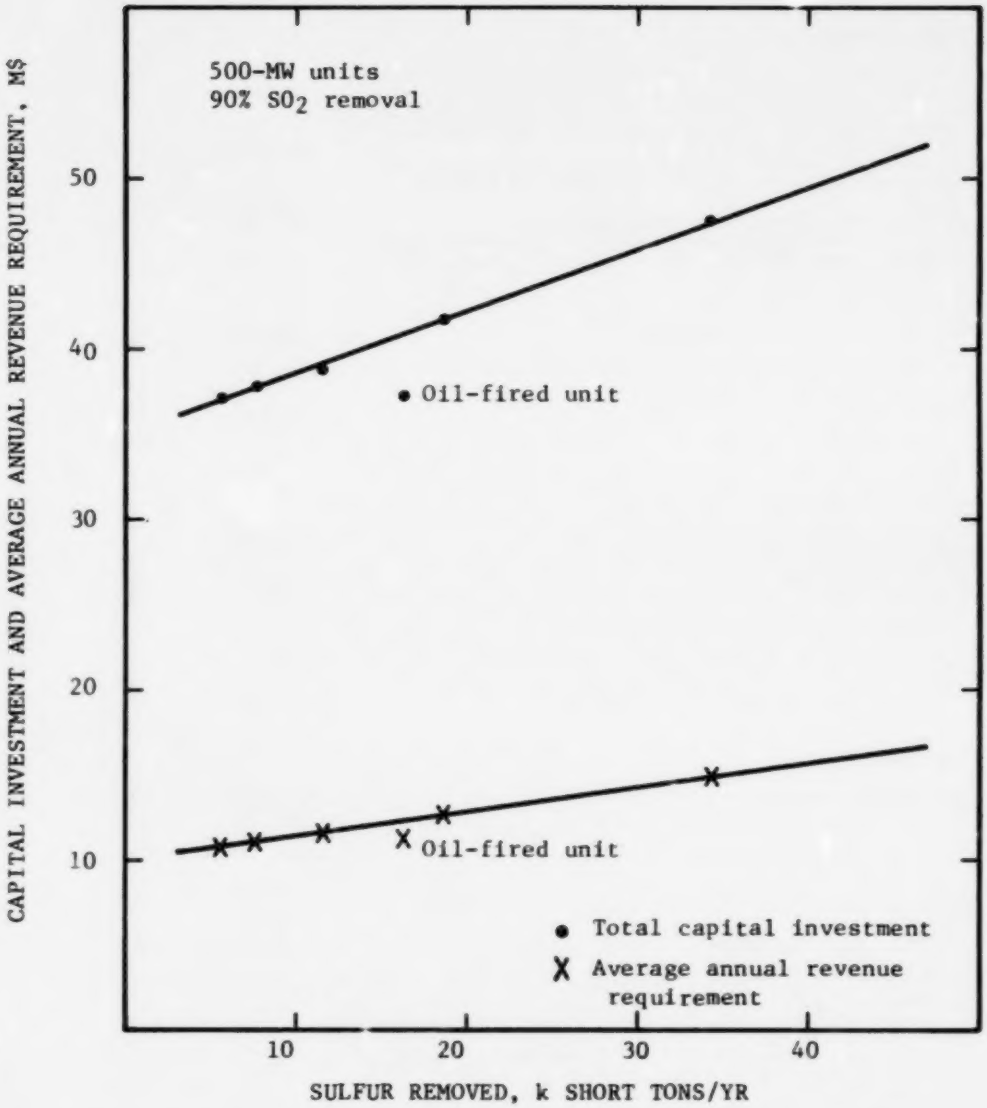

Figure B-4. Lime sludge process. Effect of sulfur removed on capital investment and annual revenue requirements.

TABLE B-7. LIME SLUDGE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silo, and bin)	1,324,000	5.2
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	859,000	3.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,950,000	19.4
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,280,000	36.4
Stack gas reheat (four indirect steam reheaters)	1,292,000	5.1
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,975,000	7.8
Subtotal	19,680,000	77.3
Services, utilities, and miscellaneous	1,181,000	4.6
Total process areas excluding pond construction	20,861,000	81.9
Pond construction	4,617,000	18.1
Total direct investment	25,478,000	100.0
Indirect Investment		
Engineering design and supervision	1,041,000	4.1
Architect and engineering contractor	229,000	0.9
Construction expense	3,574,000	14.0
Contractor fees	1,125,000	4.4
Total indirect investment	5,969,000	23.4
Contingency	6,289,000	24.7
Total fixed investment	37,736,000	148.1
Other Capital Charges		
Allowance for startup and modifications	3,312,000	13.0
Interest during construction	4,528,000	17.8
Total depreciable investment	45,576,000	178.9
Land	917,000	3.6
Working capital	1,250,000	4.9
Total capital investment	47,743,000	187.4

[a] Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE B-8. LIME SLUDGE PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	67,500 tons	40.00/ton	2,700,000	18.03
Total raw materials cost			2,700,000	18.03
Conversion costs				
Operating labor and supervision	24,060 man-hr	12.50/man-hr	300,800	2.01
Utilities				
Steam	418,200 MBtu	2.00/MBtu	836,400	5.59
Process water	205,600 kgal	0.12/kgal	24,700	0.16
Electricity	44,688,600 kWh	0.029/kWh	1,296,000	8.66
Maintenance				
Labor and material			1,807,400	12.07
Analyses	3,220 man-hr	17.00/man-hr	54,700	0.37
Total conversion costs			4,320,000	28.86
Total direct costs			7,020,000	46.89
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,734,600	18.26
Average cost of capital and taxes at 8.6% of total capital investment			4,105,900	27.43
Overheads				
Plant, 50% of conversion costs less utilities			1,081,500	7.22
Administrative, 10% of operating labor			30,100	0.20
Total indirect costs			7,952,100	53.11
Total average annual revenue requirements			14,972,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	4.99	11.64	0.55	438

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a. Basis

1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,166,221 metric tons/yr (1,285,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 30,947 metric tons/yr (34,120 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $25,478,000; total depreciable investment, $45,576,000; and total capital investment, $47,743,000.
All tons shown are 2,000 lb.

TABLE B-9. LIME SLUDGE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit, 0.8% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silo, and bin)	452,000	2.3
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	376,000	1.9
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	5,034,000	25.1
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,447,000	47.0
Stack gas reheat (four indirect steam reheaters)	1,315,000	6.5
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	901,000	4.5
Subtotal	17,525,000	87.3
Services, utilities, and miscellaneous	1,052,000	5.2
Total process areas excluding pond construction	18,577,000	92.5
Pond construction	1,500,000	7.5
Total direct investment	20,077,000	100.0
Indirect Investment		
Engineering design and supervision	929,000	4.6
Architect and engineering contractor	217,000	1.1
Construction expense	3,008,000	15.0
Contractor fees	938,000	4.7
Total indirect investment	5,092,000	25.4
Contingency	5,034,000	25.1
Total fixed investment	30,203,000	150.5
Other Capital Charges		
Allowance for startup and modifications	2,870,000	14.3
Interest during construction	3,624,000	18.0
Total depreciable investment	36,697,000	182.8
Land	306,000	1.5
Working capital	792,000	3.9
Total capital investment	37,795,000	188.2

a. Basis
Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE B-10. LIME SLUDGE PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit, 0.8% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	15,800 tons	40.00/ton	632,000	5.71
Total raw materials cost			632,000	5.71
Conversion costs				
Operating labor and supervision	24,060 man-hr	12.50/man-hr	300,800	2.72
Utilities				
Steam	428,500 MBtu	2.00/MBtu	857,000	7.75
Process water	165,900 kgal	0.12/kgal	19,900	0.18
Electricity	44,498,900 kWh	0.029/kWh	1,290,500	11.66
Maintenance				
Labor and material			1,531,200	13.84
Analyses	1,350 man-hr	17.00/man-hr	23,000	0.21
Total conversion costs			4,022,400	36.36
Total direct costs			4,654,400	42.07
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,201,800	19.90
Average cost of capital and taxes at 8.6% of total capital investment			3,250,400	29.38
Overheads				
Plant, 50% of conversion costs less utilities			927,500	8.38
Administrative, 10% of operating labor			30,100	0.27
Total indirect costs			6,409,800	57.93
Total average annual revenue requirements			11,064,200	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	3.69	7.79	0.41	1386

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a. Basis

1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6000 hr/yr.
Coal burned, 1,288,938 metric tons/yr (1,421,100 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 7,238 metric tons/yr (7,980 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $20,077,000; total depreciable investment, $36,697,000; and total capital investment, $37,795,000.
All tons shown are 2,000 lb.

TABLE B-11. LIME SLUDGE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit, 1.4% S in coal; 90% SO_2 removal; pond disposal of waste solids)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silo, and bin)	605,000	2.9
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	470,000	2.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,915,000	23.8
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,215,000	44.6
Stack gas reheat (four indirect steam reheaters)	1,283,000	6.2
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,116,000	5.4
Subtotal	17,604,000	85.2
Services, utilities, and miscellaneous	1,056,000	5.1
Total process areas excluding pond construction	18,660,000	90.3
Pond construction	2,005,000	9.7
Total direct investment	20,665,000	100.0
Indirect Investment		
Engineering design and supervision	950,000	4.6
Architect and engineering contractor	219,000	1.1
Construction expense	3,068,000	14.9
Contractor fees	959,000	4.6
Total indirect investment	5,196,000	25.2
Contingency	5,172,000	25.0
Total fixed investment	31,033,000	150.2
Other Capital Charges		
Allowance for startup and modifications	2,903,000	14.0
Interest during construction	3,724,000	18.0
Total depreciable investment	37,660,000	182.2
Land	405,000	2.0
Working capital	847,000	4.1
Total capital investment	38,912,000	188.3

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[a] Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE B-12. LIME SLUDGE PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit, 1.4% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	23,400 tons	40.00/ton	936,000	8.14
Total raw materials cost			936,000	8.14
Conversion costs				
Operating labor and supervision	24,060 man-hr	12.50/man-hr	300,800	2.62
Utilities				
Steam	414,100 MBtu	2.00/MBtu	828,200	7.20
Process water	167,200 kgal	0.12/kgal	20,100	0.17
Electricity	43,220,400 kWh	0.029/kWh	1,253,400	10.90
Maintenance				
Labor and material			1,553,000	13.51
Analyses	1,710 man-hr	17.00/man-hr	29,100	0.25
Total conversion costs			3,984,600	34.65
Total direct costs			4,920,600	42.79
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,259,600	19.65
Average cost of capital and taxes at 8.6% of total capital investment			3,346,400	29.11
Overheads				
Plant, 50% of conversion costs less utilities			941,500	8.19
Administrative, 10% of operating labor			30,100	0.26
Total indirect costs			6,577,600	57.21
Total average annual revenue requirements			11,498,200	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	3.83	10.73	0.43	970

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a. Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 971,941 metric tons/yr (1,071,600 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 10,748 metric tons/yr (11,850 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $20,665,000; total depreciable investment, $37,660,000; and total capital investment, $38,912,000.
All tons shown are 2,000 lb.

TABLE B-13. LIME SLUDGE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit, 2.0% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silo, and bin)	851,000	3.8
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	612,000	2.7
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,930,000	22.1
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,243,000	41.4
Stack gas reheat (four indirect steam reheaters)	1,287,000	5.8
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,432,000	6.4
Subtotal	18,355,000	82.2
Services, utilities, and miscellaneous	1,101,000	5.0
Total process areas excluding pond construction	19,456,000	87.2
Pond construction	2,867,000	12.8
Total direct investment	22,323,000	100.0
Indirect Investment		
Engineering design and supervision	983,000	4.4
Architect and engineering contractor	223,000	1.0
Construction expense	3,248,000	14.5
Contractor fees	1,017,000	4.6
Total indirect investment	5,471,000	24.5
Contingency	5,559,000	24.9
Total fixed investment	33,353,000	149.4
Other Capital Charges		
Allowance for startup and modifications	3,049,000	13.7
Interest during construction	4,002,000	17.9
Total depreciable investment	40,404,000	181.0
Land	572,000	2.6
Working capital	976,000	4.3
Total capital investment	41,952,000	187.9

[a] Basis
Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE B-14. LIME SLUDGE PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit, 2.0% S in coal;
90% SO_2 removal; pond disposal of waste solids)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	37,200 tons	40.00/ton	1,488,000	11.77
Total raw materials cost			1,488,000	11.77
Conversion costs				
Operating labor and supervision	24,060 man-hr	12.50/man-hr	300,800	2.38
Utilities				
Steam	416,000 MBtu	2.00/MBtu	832,000	6.58
Process water	179,400 kgal	0.12/kgal	21,500	0.17
Electricity	43,743,700 kWh	0.029/kWh	1,268,600	10.03
Maintenance				
Labor and material			1,642,500	12.99
Analyses	2,250 man-hr	17.00/man-hr	38,300	0.30
Total conversion costs			4,103,700	32.45
Total direct costs			5,591,700	44.22
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,424,200	19.17
Average cost of capital and taxes at 8.6% of total capital investment			3,607,900	28.53
Overheads				
Plant, 50% of conversion costs less utilities			990,800	7.84
Administrative, 10% of operating labor			30,100	0.24
Total indirect costs			7,053,000	55.78
Total average annual revenue requirements			12,644,700	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	4.21	10.30	0.47	672

[a] Basis

1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,113,161 metric tons/yr (1,227,300 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 17,043 metric tons/yr (18,790 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $22,323,000; total depreciable investment, $40,404,000; and total capital investment, $41,952,000.
All tons shown are 2,000 lb.

TABLE B-15. LIME SLUDGE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new lignite-fired power unit, 0.5% S in lignite;
90% SO_2 removal; pond disposal of waste solids)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silo, and bin)	358,000	1.8
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	314,000	1.6
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	5,118,000	25.9
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	9,633,000	48.8
Stack gas reheat (four indirect steam reheaters)	1,341,000	6.8
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	758,000	3.8
Subtotal	17,522,000	88.7
Services, utilities, and miscellaneous	1,051,000	5.4
Total process areas excluding pond construction	18,573,000	94.1
Pond construction	1,175,000	5.9
Total direct investment	19,748,000	100.0
Indirect Investment		
Engineering design and supervision	914,000	4.6
Architect and engineering contractor	216,000	1.1
Construction expense	2,974,000	15.1
Contractor fees	927,000	4.7
Total indirect investment	5,031,000	25.5
Contingency	4,956,000	25.1
Total fixed investment	29,735,000	150.6
Other Capital Charges		
Allowance for startup and modifications	2,856,000	14.5
Interest during construction	3,568,000	18.0
Total depreciable investment	36,159,000	183.1
Land	243,000	1.2
Working capital	763,000	3.9
Total capital investment	37,165,000	188.2

a. Basis
Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE B-16. LIME SLUDGE PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new lignite-fired power unit, 0.5% S in lignite;
90% SO_2 removal; pond disposal of waste solids)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	11,500 tons	40.00/ton	460,000	4.24
Total raw materials cost			460,000	4.24
Conversion costs				
Operating labor and supervision	24,060 man-hr	12.50/man-hr	300,800	2.78
Utilities				
Steam	439,600 MBtu	2.00/MBtu	879,200	8.11
Process water	166,300 kgal	0.12/kgal	20,000	0.18
Electricity	45,522,200 kWh	0.029/kWh	1,320,100	12.18
Maintenance				
Labor and material			1,521,100	14.05
Analyses	1,110 man-hr	17.00/man-hr	18,900	0.17
Total conversion costs			4,060,100	37.47
Total direct costs			4,520,100	41.71
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,169,500	20.02
Average cost of capital and taxes at 8.6% of total capital investment			3,196,200	29.50
Overheads				
Plant, 50% of conversion costs less utilities			920,400	8.49
Administrative, 10% of operating labor			30,100	0.28
Total indirect costs			6,316,200	58.29
Total average annual revenue requirements			10,836,300	100.00

	Mills/kWh	$/ton lignite burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	3.61	6.34	0.40	1865

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a. Basis

1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Lignite burned, 1,549,882 metric tons/yr (1,708,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 5,270 metric tons/yr (5,810 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $19,748,000; total depreciable investment, $36,159,000; and total capital investment, $37,165,000.
All tons shown are 2,000 lb.

TABLE B-17. LIME SLUDGE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new oil-fired power unit, 2.5% S in oil;
90% SO_2 removal; pond disposal of waste solids)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silo, and bin)	756,000	3.8
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	558,000	2.8
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,371,000	22.2
SO_2 absorption (four TCA scrubbers including presaturators and entrainment separators, recirculation tanks, agitators, and pumps)	8,101,000	41.3
Stack gas reheat (four direct oil-fired reheaters)	1,127,000	5.7
Solids disposal (onsite disposal facilities including feed tank, agitator, slurry disposal pumps, and pond water return pumps)	1,313,000	6.7
Subtotal	16,226,000	82.5
Services, utilities, and miscellaneous	974,000	5.0
Total process areas excluding pond construction	17,200,000	87.5
Pond construction	2,458,000	12.5
Total direct investment	19,658,000	100.0
Indirect Investment		
Engineering design and supervision	968,000	4.9
Architect and engineering contractor	221,000	1.1
Construction expense	2,925,000	14.9
Contractor fees	923,000	4.7
Total indirect investment	5,037,000	25.6
Contingency	4,939,000	25.1
Total fixed investment	29,634,000	150.7
Other Capital Charges		
Allowance for startup and modifications	2,718,000	13.8
Interest during construction	3,556,000	18.2
Total depreciable investment	35,908,000	182.7
Land	493,000	2.5
Working capital	885,000	4.5
Total capital investment	37,286,000	189.7

[a] Basis
Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by direct oil fired reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE B-18. LIME SLUDGE PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new oil-fired power unit, 2.5% S in oil;
90% SO_2 removal; pond disposal of waste solids)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	31,700 tons	40.00/ton	1,268,000	11.14
Total raw materials cost			1,268,000	11.14
Conversion costs				
Operating labor and supervision	24,060 man-hr	12.50/man-hr	300,800	2.64
Utilities				
Fuel oil (No. 6)	2,418,100 gal	0.40/gal	967,300	8.49
Process water	150,600 kgal	0.12/kgal	18,100	0.16
Electricity	36,723,100 kWh	0.029/kWh	1,065,000	9.35
Maintenance				
Labor and material			1,449,700	12.73
Analyses	2,050 man-hr	17.00/man-hr	34,900	0.31
Total conversion costs			3,835,800	33.68
Total direct costs			5,103,800	44.82
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,154,500	18.92
Average cost of capital and taxes at 8.6% of total capital investment			3,206,600	28.16
Overheads				
Plant, 50% of conversion costs less utilities			892,700	7.84
Administrative, 10% of operating labor			30,100	0.26
Total indirect costs			6,283,900	55.18
Total average annual revenue requirements			11,387,700	100.00

	Mills/kWh	$/bbl oil burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	3.80	2.55	0.42	710

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a. Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Oil burned, 710 x 10^6 liters/yr (4,464,300 bbl/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 14,530 metric tons/yr (16,020 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $19,658,000; total depreciable investment, $35,908,000; and total capital investment, $37,286,000.
All tons shown are 2,000 lb.

APPENDIX C

DOUBLE-ALKALI SLUDGE PROCESS

PROCESS DESCRIPTION

The double-alkali process evaluated in this study has been generalized from several concentrated-mode double-alkali processes in the United States. A two-tray tower absorber with presaturator and mist eliminator is used. The scrubbing liquor is a solution of sodium salts of which sodium sulfite (Na_2SO_3) is the major active component. The SO_2 reacts with the Na_2SO_3 to form sodium bisulfite ($NaHSO_3$). A bleedstream of absorber liquor is treated with slaked lime to precipitate calcium sulfur salts and regenerate the Na_2SO_3.

Pebble lime is slaked and then reacted with a bleedstream of absorber effluent in agitated tanks. The reaction product, predominately calcium sulfite, flows to a thickener where the slurry is concentrated to 40% solids. This stream is further dewatered using drum filters to produce a cake containing 55% solids. The filter is designed with two wash sections to minimize sodium loss. The filter cake is conveyed to a reslurry tank where it is mixed with pond return water to a 15% solids slurry. The slurry is pumped to an earthen-diked clay-lined pond one mile away where the solids in the slurry settle to form a sludge containing approximately 40% solids. Makeup soda ash is added to the regenerated scrubber liquor at the thickener overflow storage tank.

The flow diagram for double-alkali sludge is shown in Figure C-1. The base-case material balance and equipment list are shown in Tables C-1 and C-2.

SPECIFIC PROCESS PREMISES

1. The flue gas is cooled from 149°C (300°F) to 53°C (127°F) and saturated in the presaturator. The presaturator has an L/G ratio of 0.5 liter/m^3 (4 gal/10^3 aft^3).
2. A two-tray tower absorber with a superficial velocity of 2.1 m/sec (7 ft/sec), and a pressure drop, including the mist eliminator, of 1.25 kPa (5 inches H_2O) is used. An L/G ratio of 0.5 liter/m^3 (4 gal/10^3 aft^3) is used for recycle liquor to the absorber and an L/G ratio of 0.4 liter/m^3 (3 gal/aft^3) is used for the regenerated scrubbing liquor to the absorber.

3. Stoichiometry is 1.0 mole of CaO to 1.0 mole of SO_2 removed and 1 mole of CaO to 2 moles of HCl removed.
4. Oxidation of 10% of the SO_2 removed to sulfate is assumed. The remainder is assumed to be in sulfite form.

ENERGY REQUIREMENTS

For base-case conditions, reheat of the cleaned gas from 53°C to 79°C requires 42.2×10^3 kg/hr (93,060 lb/hr) of 243°C (470°F) steam at 3.55×10^3 kPa absolute pressure (500 psig), equivalent to about 17.62×10^6 kcal/hr.

The electrical power demand for the base case is estimated to be about 3,981 kW or 0.8% of the rated output of a 500-MW power plant. For 6,000 hours of operation, the annual electrical energy consumption is 23.9×10^6 kWh.

The total equivalent energy consumption for the base case is approximately 28.61×10^6 kcal/hr or 2.5% of the input energy required for the 500-MW power unit. Summarized energy requirements for all cases are listed in Table C-3.

BYPRODUCT MANAGEMENT

ESP units remove 99.2% of the fly ash from the flue gas and, therefore, only a small amount of fly ash is found in the FGD process sludge. (Fly ash emission from oil-fired units does not exceed the EPA particulate emission standard and fly ash-collection facilities are not included in oil-fired power plant design.) Projected mass flow rates of byproduct wastes for the base case are shown below.

Component	Kg/hr	Lb/hr
$CaSO_3 \cdot 1/2H_2O$	18,266	40,270
$CaSO_4 \cdot 2H_2O$	2,158	4,758
$Ca(OH)_2$	209	461
Na_2SO_3	319	703
Na_2SO_4	148	326
NaCl	456	1,006
Mg	117	258
Fly ash	149	329
Inerts	98	215
	21,920	48,326

Based on a 30-yr life for both the power unit and the FGD unit, the sludge disposal pond for the base case requires approximately 99 hectares (245 acres). It is designed for an optimum depth of approximately 5.8 meters (19 feet). Pond size is listed by case in Table C-4.

ECONOMIC EVALUATION

Capital investment and annual revenue requirement summaries for the base case and five fuel variations are shown in Tables C-5 and C-6. Detailed economic results are shown in Tables C-7 through C-18. The results showing the estimated range of accuracy are shown in Figures C-2 and C-3. The effects of different fuel sulfur contents are shown in Figures C-4 and C-5.

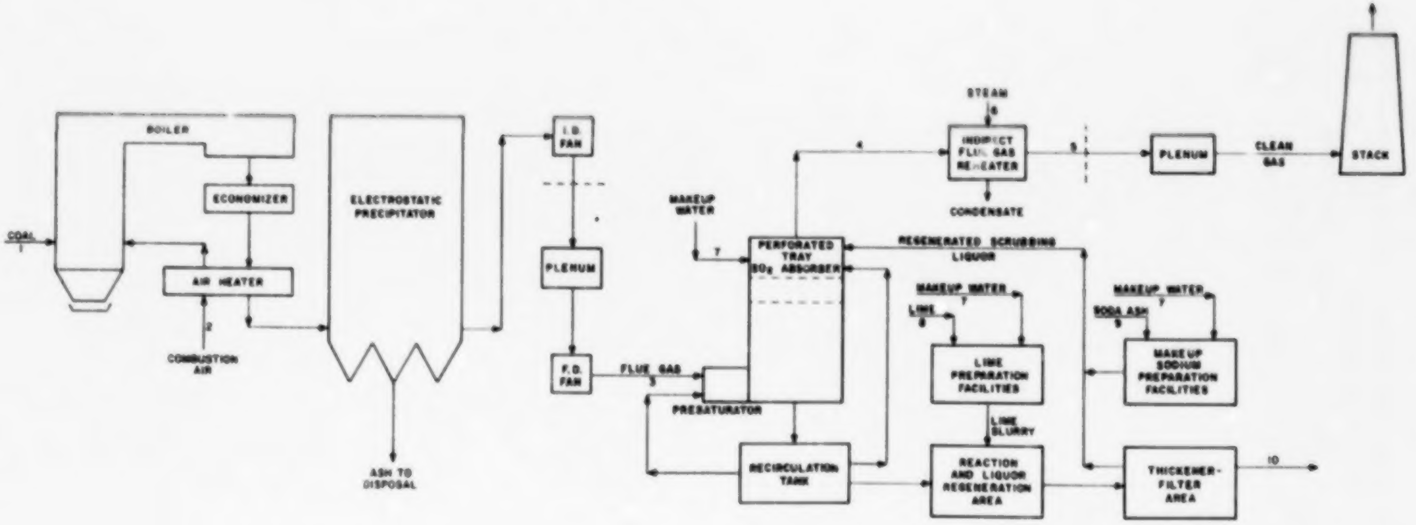
BOILER
COAL
1
ECONOMIZER
AIR HEATER
2
COMBUSTION AIR
ELECTROSTATIC PRECIPITATOR
ASH TO DISPOSAL
I.D. FAN
PLENUM
F.D. FAN
FLUE GAS
3
PRESATURATOR
MAKEUP WATER
7
PERFORATED TRAY SO_2 ABSORBER
RECIRCULATION TANK
4
STEAM
6
INDIRECT FLUE GAS RE-HEATER
CONDENSATE
5
PLENUM
CLEAN GAS
STACK
REGENERATED SCRUBBING LIQUOR
MAKEUP WATER
7
LIME
8
LIME PREPARATION FACILITIES
LIME SLURRY
REACTION AND LIQUOR REGENERATION AREA
MAKEUP WATER
7
SODA ASH
9
MAKEUP SODIUM PREPARATION FACILITIES
THICKENER-FILTER AREA
10

Figure C-1. Double-alkali sludge process flow diagram.

TABLE C-1. DOUBLE-ALKALI SLUDGE PROCESS

MATERIAL BALANCE - BASE CASE (3.5% SULFUR COAL)

	Stream No.	1	2	3	4	5
	Description	Coal to boiler	Combustion air to air heater	Gas to presaturator-absorber	Gas to reheater	Gas to stack
1	Total stream, 1000 kg/hr	194	2,062	2,225	2,317	2,317
2	Total stream, lb/hr	428,600	4,546,200	4,906,000	5,107,500	5,107,500
3	Gas flow, Nm^3/hr (0^oC)		1,615,700	1,697,700	1,812,400	1,815,300
4	Gas flow, sft^3/min (60^oF)		1,005,000	1,056,000	1,127,300	1,129,100
5	Liquid flow, liters/min				38.6	
6	Liquid flow, gal/min				10.2	
7	Temperature, ^oC		27	149	53	79
8	Particulates, kg/hr			199.1	49.8	49.8
9	Particulates, lb/hr			439	110	110
10						

	Stream No.	6	7	8	9	10
	Description	Steam to reheater	Process makeup water	Lime to preparation facilities	Makeup soda ash	Filtered sludge
1	Total stream, 1000 kg/hr	42	129	10	1	39
2	Total stream, lb/hr	93,060	283,200	21,470	1,755	85,570
3	Liquid flow, liters/min		2,143			
4	Liquid flow, gal/min		566			
5	Temperature, ^oC	243				
6	Temperature, ^oF	470				
7	Pressure, Pascals (abs)	3.55×10^6				
8	Pressure, psig	500				
9	Specific gravity					1.3
10	Undissolved solids, %					55

1						
2						
3						
4						
5						
6						
7						
8						
9						
10						

1						
2						
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4						
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7						
8						
9						
10						

TABLE C-2. DOUBLE-ALKALI SLUDGE PROCESS

BASE-CASE EQUIPMENT LIST
DESCRIPTION AND COST

Area 1--Materials Handling				Area size-cost exponent 0.72	
	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1.	Conveyor, lime storage (enclosed)	1	Belt, 24 in. wide x 1,500 ft long, 30 hp, 100 tons/hr, 150 ft/min	155,800	52,300
2.	Elevator, lime storage	1	Continuous, bucket 16 in. x 8 in. x 11-3/4 in., 75 hp, 120 ft lift, 100 tons/hr, 160 ft/min	102,900	2,400
3.	Silo, lime storage	1	50 ft dia x 74 ft straight side, 145,300 ft^3, 60^o slope, 3/8 in. carbon steel	88,400	246,100
4.	Feeder, reclaim	1	Vibrating pan, 3-1/2 hp, 40 tons/hr	12,200	2,100
5.	Conveyor, live lime feed (enclosed)	1	Belt, 18 in. wide x 100 ft long, 2 hp, 40 tons/hr. 100 ft/min	23,400	4,800
6.	Elevator, live lime feed	1	Continuous, bucket 11 in. x 6 in. x 8-3/4 in., 50 hp, 50 ft lift, 40 tons/hr, 160 ft/min, with diverter gate	56,000	1,100
7.	Bin, lime feed	2	10 ft dia x 15 ft high, w/cover, carbon steel	5,400	11,300
8.	Conveyor, soda ash storage	1	Pneumatic, vacuum, 40 hp	65,000	20,000
9.	Silo, soda ash storage	1	16 ft dia x 32 ft straight side, 5,930 ft^3, 60^o slope, carbon steel	10,400	16,400
	Vibrators	4		5,600	1,200

(continued)

TABLE C-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
10. Dust collecting system	1	Bag filter, polypropylene bag, 8,800 aft^3/min, 7-1/2 hp, automatic shaker system	12,000	28,200
Subtotal			537,100	385,900

Area 2--Feed Preparation

Area size-cost exponent 0.55

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Feeder, lime bin discharge	2	Vibrating, 3-1/2 hp, carbon steel	9,200	3,700
2. Feeder, slaker weigh	2	Screw, 12 in. dia x 12 ft long, 1 hp, 5-1/2 tons/hr	12,000	1,400
3. Slaker	2	7 ft wide x 28 ft long, 10 hp slaker, 2 hp classifier, 5-1/2 tons/hr	116,300	12,100
4. Tank, slaker product	2	7 ft dia x 6 ft high, 1,727 gal, open top, four 7 in. baffles, agitator supports, carbon steel (10 min residence time)	1,800	3,200
Lining		1/4 in. neoprene lining	2,000	2,400
5. Agitator, slaker product tank	2	30 in. dia, 5 hp, neoprene coated	17,500	1,700
6. Pump, slaker product tank	3	Centrifugal, 140 gpm, 100 ft head, 7-1/2 hp, carbon steel, neoprene lined (2 operating, 1 spare)	11,100	2,300
7. Tank, slurry feed	1	31 ft dia x 31 ft high, 171,600 gal, open top, four 31 in. baffles, agitator supports, carbon steel (8 hr residence time)	21,400	39,000
Lining		1/4 in. neoprene lining	21,900	26,700

(continued)

TABLE C-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
8. Agitator, slurry feed tank	1	1 turbine, 124 in. dia, 25 hp, neoprene coated	29,300	1,700
9. Pump, slurry feed tank	2	Centrifugal, 325 gpm, 100 ft head, 20 hp, carbon steel, neoprene lined (1 operating, 1 spare)	8,600	3,000
10. Feeder, soda ash silo discharge	1	Rotary air lock, 2 hp	5,000	500
11. Feeder, soda ash solution tank	1	Weigh belt, 18 in. x 20 ft long, 1-1/2 hp, 1 ton/hr	5,400	2,000
12. Tank, soda ash solution	1	12-1/2 ft dia x 12-1/2 ft high, 11,100 gal, open top, four 12.5 in. baffles, agitator supports, carbon steel (8 hr residence)	3,700	6,200
Lining		1/4 in. neoprene lining	3,600	4,300
13. Agitator, soda ash solution tank	1	48 in. dia, 5 hp, neoprene coated	9,000	900
14. Pump, soda ash solution tank	2	21 gpm, 60 ft head, 1 hp, carbon steel, neoprene lined (1 operating, 1 spare)	3,500	1,200
15. Dust collecting system	1	Bag filter, polypropylene bag, 8,800 aft^3/min, 7-1/2 hp, automatic shaker system (one-half cost in material handling)	12,000	28,200
Subtotal			293,300	140,500

(continued)

TABLE C-2 (continued)

Area 3--Gas Handling			Area size-cost exponent 0.68	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Fans	4	Forced draft, 8 in. static head, 700 rpm, 800 hp, fluid drive	772,000	68,000
Subtotal			772,000	68,000

Area 4--SO_2 Absorption			Area size-cost exponent 0.79	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. SO_2 absorber	4	Tray tower, 31 ft dia x 40 ft nigh, 3/8 in. carbon steel, flake lined; 2-316 SS sieve trays, 316 SS nozzles, polypropylene entrainment separator	3,316,800	490,000
2. Tank, recirculation	4	28 ft dia x 30 ft high, 137,350 gal, open top, four 28 in. baffles, agitator supports, carbon steel (10 min residence time)	76,000	135,200
Lining		1/4 in. neoprene lining	75,600	92,400
3. Agitator, recirculation tank	4	108 in. dia, 25 hp, neoprene coated	117,300	6,800
4. Pump, presaturator	6	Centrifugal, 1,274 gpm, 60 ft head, 50 hp, carbon steel, neoprene lined (4 operating, 2 spare)	48,900	11,200
5. Pump, liquor recirculation	6	Centrifugal, 1,910 gpm, 100 ft head, 100 hp, carbon steel, neoprene lined (4 operating, 2 spare)	64,000	11,900

(continued)

TABLE C-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
6. Pump, bleed to reaction tank	6	Centrifugal, 870 gpm, 100 ft head, 50 hp, carbon steel, neoprene lined (4 operating, 2 spare)	34,700	11,200
7. Pump, makeup water	2	Centrifugal, 360 gpm, 150 ft head, 30 hp, carbon steel (1 operating, 1 spare)	12,700	2,800
8. Soot blowers	40	Air, retractable	260,000	225,800
Subtotal			4,006,000	987,300

Area 5--Reheat			Area size-cost exponent 0.75	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Reheater	4	Steam, tube type, 3,600 ft^2, one-half tubes made of Inconel 625 and one-half made of Cor-Ten	856,000	39,200
2. Soot blowers	20	Air, retractable	130,000	112,900
Subtotal			986,000	152,100

Area 6--Reaction			Area size-cost exponent 0.50	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Tank, reaction	2	26 ft dia x 15 ft high, 59,570 gal, four 26 in. baffles, agitator supports, carbon steel (30 min residence time total)	20,600	36,200

(continued)

TABLE C-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. (continued)				
Lining		1/4 in. neoprene lining	18,800	22,800
2. Agitator, reaction tank	2	100 in. dia, 25 hp, neoprene coated	56,600	5,800
3. Pump, reaction tank	2	Centrifugal, 3,480 gpm, 50 ft head, 100 hp, carbon steel, neoprene lined (1 operating, 1 spare)	31,200	10,200
Subtotal			127,200	75,000

Area 7--Solids Separation

Area size-cost exponent 0.47

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Thickener	1	Carbon steel tank, 162 ft dia x 8 ft high; concrete basin, 4 ft high	134,100	342,900
Lining		1/4 in. neoprene lining	20,200	24,600
Rake motor and mechanism		7-1/2 hp	422,000	140,700
2. Pump, underflow slurry	2	Centrifugal, 302 gpm, 100 ft head, 20 hp, carbon steel, neoprene lined (1 operating, 1 spare)	9,300	3,000
3. Tank, thickener overflow storage	1	33 ft dia x 15 ft high, 96,000 gal, open top, four 33 in. baffles, agitator supports, carbon steel	14,000	23,800
Lining		1/4 in. neoprene lining	12,800	16,600

(continued)

TABLE C-2 (continued)

	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
4.	Agitator, thickener overflow storage tank	1	132 in. dia, 25 hp, neoprene coated	28,500	1,700
5.	Pump, scrubbing liquor return	6	Centrifugal, 955 gpm, 125 ft head, 60 hp, carbon steel, neoprene lined (4 operating, 2 spare)	41,600	11,400
6.	Filter	2	Rotary vacuum, 12 ft dia x 14 ft face, 20 total hp	251,300	25,500
7.	Pump, filter wash water	2	270 gpm, 80 ft head, 15 hp, carbon steel (1 operating, 1 spare)	5,000	1,300
8.	Conveyor, filter cake	1	Belt, 18 in. wide x 100 ft long, 3 hp, 45 tons/hr, 100 ft/min	23,400	4,800
	Subtotal			962,200	596,300

Area 8--Solids Disposal

Area size-cost exponent 0.52

	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1.	Tank, filter cake reslurry	1	7 ft dia x 11 ft high, 3,170 gal, open top, four 7 in. baffles, agitator supports, carbon steel (5 min residence time)	1,500	2,800
	Lining		1/4 in. neoprene lining	1,600	2,000
2.	Agitator, filter cake reslurry tank	1	Two turbines, 28 in. dia, 5 hp, neoprene coated	9,000	900

(continued)

TABLE C-2 (continued)

	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
3.	Pump, pond feed	2	Centrifugal, 570 gpm, 150 ft head, 50 hp, carbon steel, neoprene lined (1 operating, 1 spare)	22,600	6,300
4.	Pump, pond return	2	Centrifugal, 392 gpm, 150 ft head, 40 hp, carbon steel, neoprene lined (1 operating, 1 spare)	21,100	5,900
	Subtotal			55,800	17,900

TABLE C-3. DOUBLE-ALKALI SLUDGE PROCESS ENERGY REQUIREMENTS

Case	Reheat, kcal/hr	Electricity, kcal/hr (kW)	Process steam, kcal/hr	Oil, kcal/hr	Natural gas, kcal/hr	Total equivalent energy consumption,[a] % of input energy
500-MW unit						
Coal, 3.5% sulfur (base case)	17.62 M	9.03 M (3,981)	-	-	-	2.52
Coal, 0.8% sulfur	18.06 M	8.08 M (3,562)	-	-	-	2.48
Coal, 1.4% sulfur	17.45 M	7.99 M (3,525)	-	-	-	2.41
Coal, 2.0% sulfur	17.53 M	8.33 M (3,672)	-	-	-	2.45
Lignite, 0.5% sulfur	18.52 M	8.18 M (3,607)	-	-	-	2.54
Oil, 2.5% sulfur	14.67 M	7.02 M (3,095)	-	-	-	1.91

a. Based on boiler efficiency of 90% for generation of steam and a gross heat rate of 9,000 Btu/kWh for generation of electricity.

TABLE C-4. POND SIZE, DOUBLE-ALKALI SLUDGE PROCESS

Case	Area, hectares	(acres)	Depth meters	(ft)
500-MW unit				
Coal, 3.5% sulfur (base case)	99	(245)	5.8	(19)
Coal, 0.8% sulfur	33	(81)	4.6	(15)
Coal, 1.4% sulfur	44	(108)	4.9	(16)
Coal, 2.0% sulfur	62	(153)	5.2	(17)
Lignite, 0.5% sulfur	31	(78)	4.3	(14)
Oil, 2.5% sulfur	48	(119)	4.9	(16)

TABLE C-5. DOUBLE-ALKALI SLUDGE PROCESS CAPITAL INVESTMENT

Case	Total capital investment $	$/kW
500-MW unit		
Coal, 3.5% sulfur (base case)	53,231,000	107
Coal, 0.8% sulfur	40,537,000	81
Coal, 1.4% sulfur	42,179,000	84
Coal, 2.0% sulfur	46,045,000	92
Lignite, 0.5% sulfur	39,595,000	79
Oil, 2.5% sulfur	40,659,000	81

TABLE C-6. DOUBLE-ALKALI SLUDGE PROCESS ANNUAL REVENUE REQUIREMENTS

Case	$	Mills/kWh	$/ton coal (bbl oil) burned	$/MBtu heat input	$/ton sulfur removed
500-MW unit					
Coal, 3.5% sulfur (base case)	16,010,600	5.34	12.45	0.59	469
Coal, 0.8% sulfur	11,173,000	3.72	7.86	0.41	1,400
Coal, 1.4% sulfur	11,793,600	3.93	11.01	0.44	995
Coal, 2.0% sulfur	13,080,000	4.36	10.66	0.48	696
Lignite, 0.5% sulfur	10,828,000	3.61	6.34	0.40	1,863
Oil, 2.5% sulfur	11,879,500	3.96	(2.66)	0.44	741

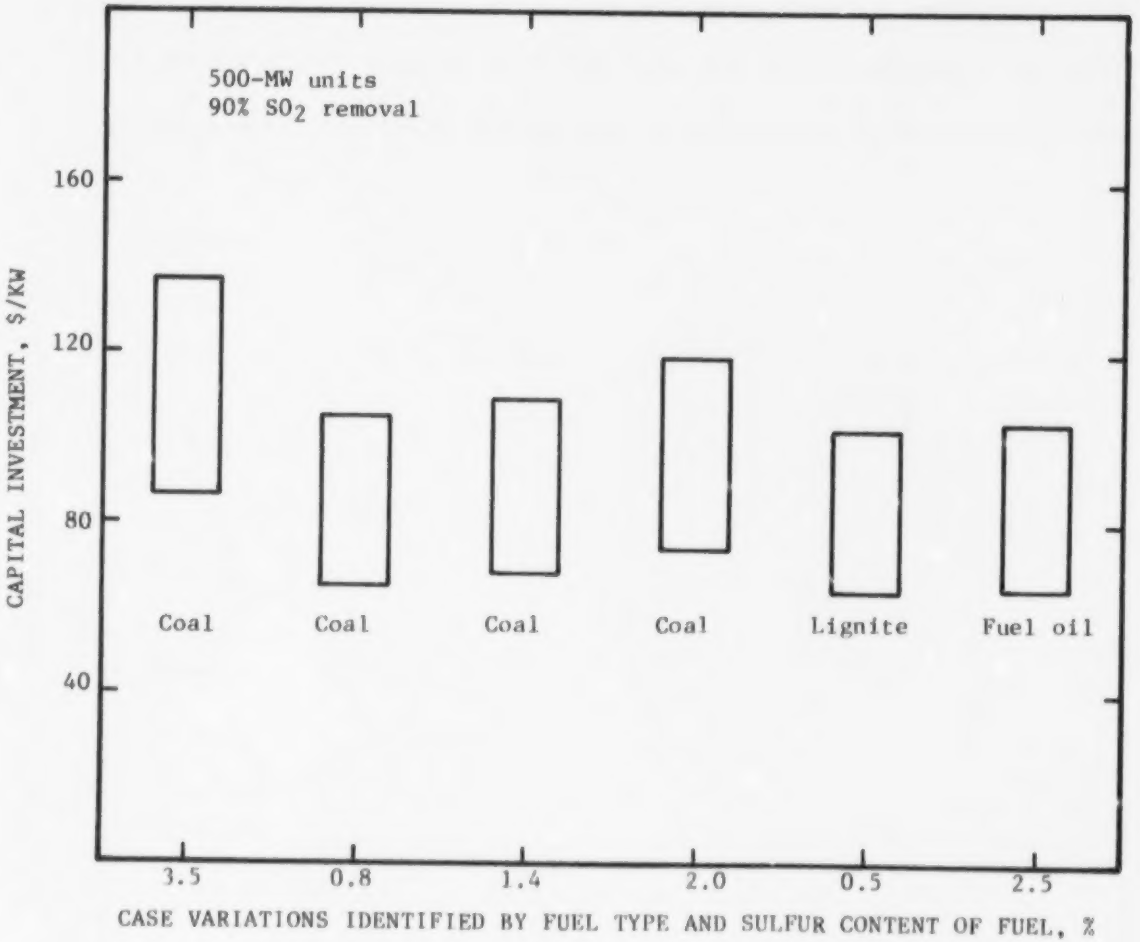

Figure C-2. Double-alkali sludge process capital investment range.

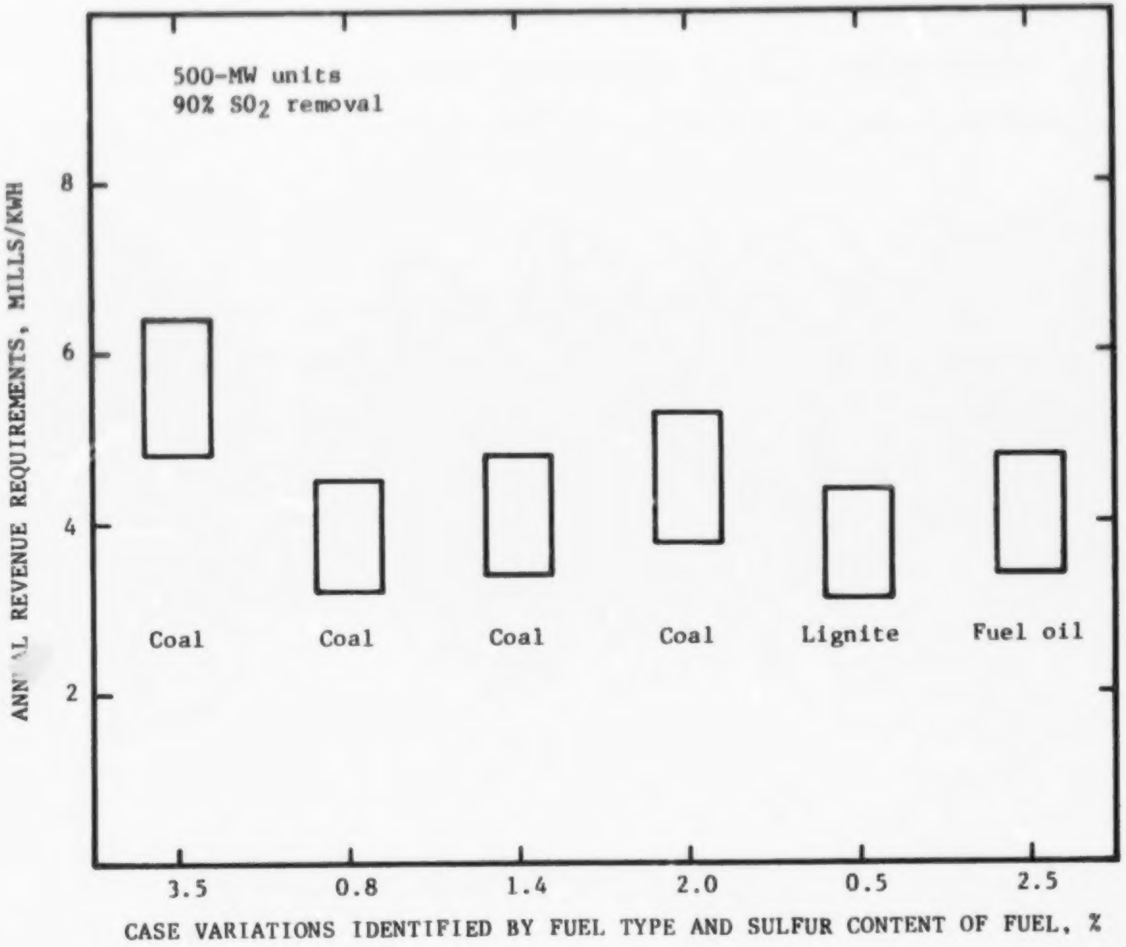

Figure C-3. Double-alkali sludge process annual revenue requirement range.

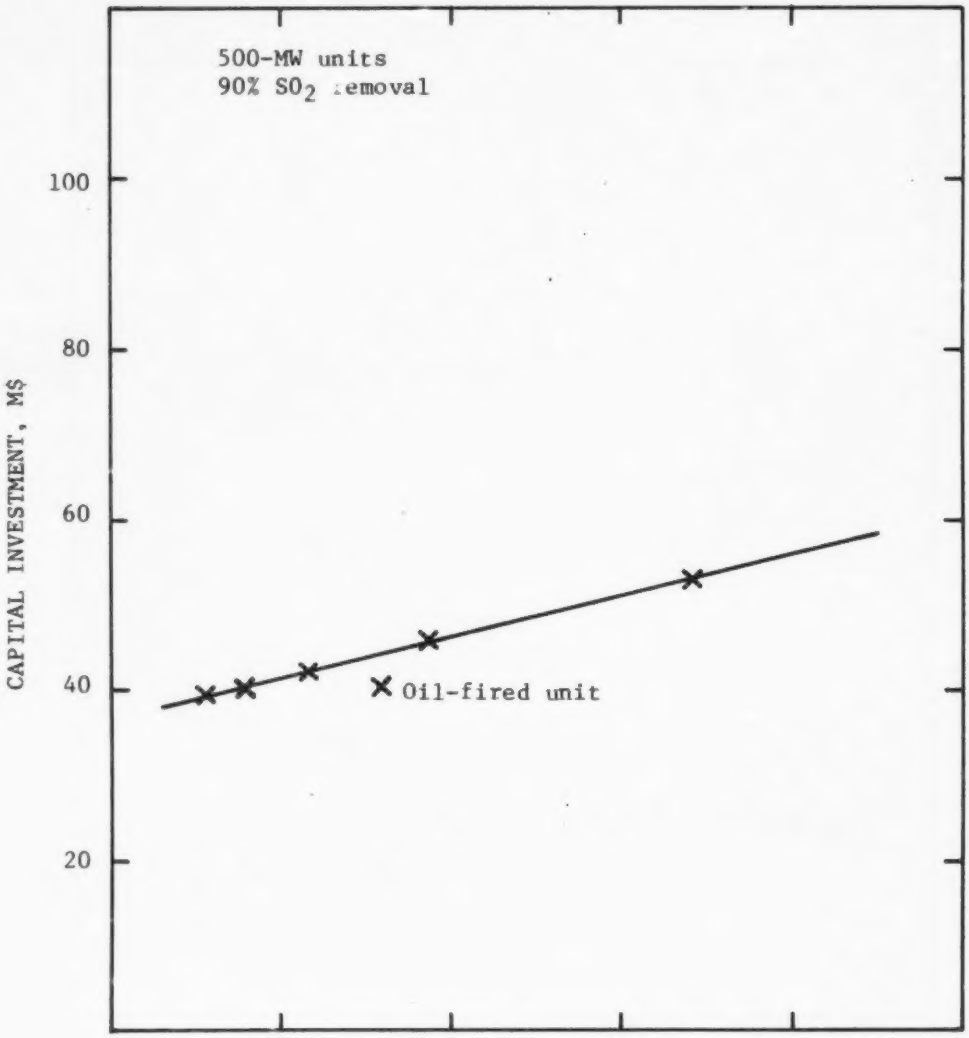

Figure C-4. Double-alkali sludge process. Effect of sulfur removed on capital investment.

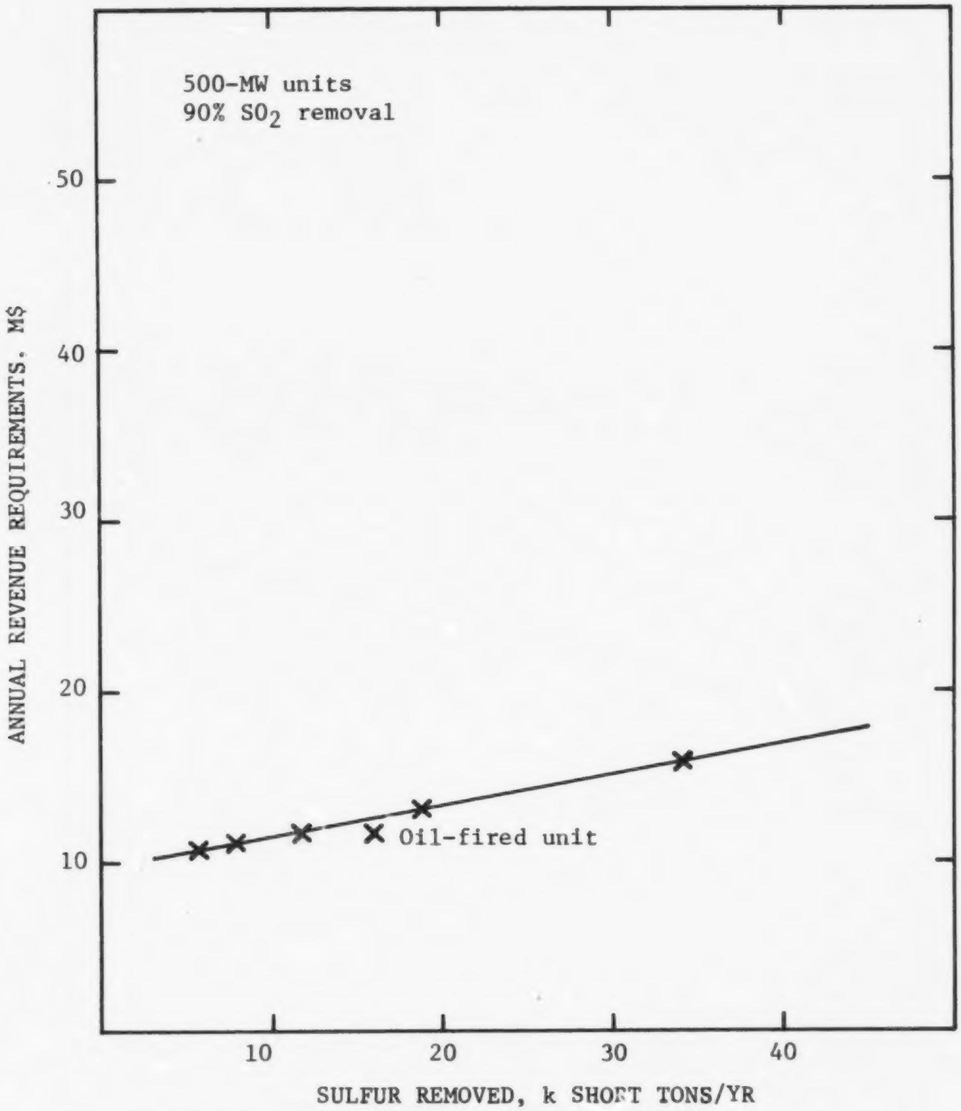

Figure C-5. Double-alkali sludge process. Effect of sulfur removed on average annual revenue requirement.

TABLE C-7. DOUBLE-ALKALI SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 3.5% sulfur
in coal; 90% SO_2 removal; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silos, and bin)	1,975,000	7.0
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	918,000	3.2
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,269,000	15.1
SO_2 absorption (four tray towers including presaturator and entrainment separators, recirculation tanks, agitators, and pumps)	9,489,000	33.5
Stack gas reheat (four indirect steam reheaters)	1,292,000	4.6
Reaction (tanks, agitators, and pumps)	385,000	1.4
Solids separation (thickener, drum filters, tanks, agitators, pumps, and conveyor)	2,554,000	9.0
Solids disposal (onsite disposal facilities including reslurry tank, agitator, slurry disposal pumps, and pond water return pumps)	1,395,000	4.9
Subtotal	22,277,000	78.7
Services, utilities, and miscellaneous	1,337,000	4.8
Total process areas excluding pond construction	23,614,000	83.5
Pond construction	4,679,000	16.5
Total direct investment	28,293,000	100.0
Indirect Investment		
Engineering design and supervision	1,423,000	5.0
Architect and engineering contractor	324,000	1.1
Construction expense	3,917,000	13.9
Contractor fees	1,218,000	4.3
Total indirect investment	6,882,000	24.3
Contingency	7,035,000	24.9
Total fixed investment	42,210,000	149.2
Other Capital Charges		
Allowance for startup and modifications	3,753,000	13.3
Interest during construction	5,065,000	17.9
Total depreciable investment	51,028,000	180.4
Land	900,000	3.2
Working capital	1,303,000	4.6
Total capital investment	53,231,000	188.2

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE C-8. DOUBLE-ALKALI SLUDGE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 3.5% sulfur in coal; 90% SO_2 removal; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	64,400 tons	40.00/ton	2,576,000	16.09
Soda ash	5,270 tons	90.00/ton	474,300	2.96
Total raw materials cost			3,050,300	19.05
Conversion costs				
Operating labor and supervision	31,900 man-hr	12.50/man-hr	398,800	2.49
Utilities				
Steam	419,600 MBtu	2.00/MBtu	839,200	5.24
Process water	203,790 kgal	0.12/kgal	24,500	0.15
Electricity	23,884,000 kWh	0.029/kWh	692,600	4.33
Maintenance				
Labor and material			2,029,500	12.68
Analyses	3,220 man-hr	17.00/man-hr	54,700	0.34
Total conversion costs			4,039,300	25.23
Total direct costs			7,089,600	44.28
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,061,700	19.13
Average cost of capital and taxes at 8.6% of total capital investment			4,577,900	28.59
Overheads				
Plant, 50% of conversion costs less utilities			1,241,500	7.75
Administrative, 10% of operating labor			39,900	0.25
Total indirect costs			8,921,000	55.72
Total average annual revenue requirements			16,010,600	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements	5.34	12.45	0.59	469

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,166,200 metric tons/yr (1,285,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 30,950 metric tons/yr (34,120 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $28,293,000; total depreciable investment, $51,028,000; and total capital investment, $53,231,000.
All tons shown are 2,000 lb.

TABLE C-9. DOUBLE-ALKALI SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 0.8% sulfur in coal; 90% SO_2 removal; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silos, and bin)	693,000	3.3
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	413,000	1.9
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,342,000	20.4
SO_2 absorption (four tray towers including presaturator and entrainment separators, recirculation tanks, agitators, and pumps)	9,669,000	45.4
Stack gas reheat (four indirect steam reheaters)	1,315,000	6.2
Reaction (tanks, agitators, and pumps)	186,000	0.9
Solids separation (thickener, drum filters, tanks, agitators, pumps, and conveyor)	1,290,000	6.0
Solids disposal (onsite disposal facilities including reslurry tank, agitator, slurry disposal pumps, and pond water return pumps)	656,000	3.1
Subtotal	18,564,000	87.2
Services, utilities, and miscellaneous	1,114,000	5.2
Total process areas excluding pond construction	19,678,000	92.4
Pond construction	1,615,000	7.6
Total direct investment	21,293,000	100.0
Indirect Investment		
Engineering design and supervision	1,314,000	6.2
Architect and engineering contractor	313,000	1.5
Construction expense	3,158,000	14.8
Contractor fees	981,000	4.6
Total indirect investment	5,766,000	27.1
Contingency	5,412,000	25.4
Total fixed investment	32,471,000	152.5
Other Capital Charges		
Allowance for startup and modifications	3,086,000	14.5
Interest during construction	3,897,000	18.3
Total depreciable investment	39,454,000	185.3
Land	326,000	1.5
Working capital	757,000	3.6
Total capital investment	40,537,000	190.4

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE C-10. DOUBLE-ALKALI SLUDGE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 0.8% sulfur in coal; 90% SO_2 removal; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	15,060 tons	40.00/ton	602,400	5.39
Soda ash	1,230 tons	90.00/ton	110,700	0.99
Total raw materials cost			713,100	6.38
Conversion costs				
Operating labor and supervision	31,900 man-hr	12.50/man-hr	398,800	3.57
Utilities				
Steam	429,900 MBtu	2.00/MBtu	859,800	7.69
Process water	167,100 kgal	0.12/kgal	20,100	0.18
Electricity	21,374,200 kWh	0.029/kWh	619,900	5.55
Maintenance				
Labor and material			1,622,700	14.52
Analyses	1,350 man-hr	17.00/man-hr	23,000	0.21
Total conversion costs			3,544,300	31.72
Total direct costs			4,257,400	38.10
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,367,200	21.19
Average cost of capital and taxes at 8.6% of total capital investment			3,486,200	31.20
Overheads				
Plant, 50% of conversion costs less utilities			1,022,300	9.15
Administrative, 10% of operating labor			39,900	0.36
Total indirect costs			6,915,600	61.90
Total average annual revenue requirements			11,173,000	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements	3.72	7.86	0.41	1,400

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,288,900 metric tons/yr (1,421,100 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 7,240 metric tons/yr (7,980 short tons/yr).
Investment and revenue requirements for removal and disposal of fly ash excluded.
Total direct investment, $21,293,000; total depreciable investment, $39,454,000; and total capital investment, $40,537,000.
All tons shown are 2,000 lb.

TABLE C-11. DOUBLE-ALKALI SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 1.4% sulfur in coal; 90% SO_2 removal; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silos, and bin)	922,000	4.2
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	513,000	2.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,239,000	19.1
SO_2 absorption (four tray towers including presaturator and entrainment separators, recirculation tanks, agitators, and pumps)	9,413,000	42.4
Stack gas reheat (four indirect steam reheaters)	1,283,000	5.8
Reaction (tanks, agitators, and pumps)	227,000	1.0
Solids separation (thickener, drum filters, tanks, agitators, pumps, and conveyor)	1,553,000	7.0
Solids disposal (onsite disposal facilities including reslurry tank, agitator, slurry disposal pumps, and pond water return pumps)	805,000	3.6
Subtotal	18,955,000	85.4
Services, utilities, and miscellaneous	1,137,000	5.2
Total process areas excluding pond construction	20,092,000	90.6
Pond construction	2,091,000	9.4
Total direct investment	22,183,000	100.0
Indirect Investment		
Engineering design and supervision	1,334,000	6.0
Architect and engineering contractor	315,000	1.4
Construction expense	3,256,000	14.7
Contractor fees	1,012,000	4.6
Total indirect investment	5,917,000	26.7
Contingency	5,620,000	25.3
Total fixed investment	33,720,000	152.0
Other Capital Charges		
Allowance for startup and modifications	3,163,000	14.3
Interest during construction	4,046,000	18.2
Total depreciable investment	40,929,000	184.5
Land	420,000	1.9
Working capital	830,000	3.7
Total capital investment	42,179,000	190.1

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE C-12. DOUBLE-ALKALI SLUDGE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 1.4% sulfur in coal; 90% SO_2 removal; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	22,360 tons	40.00/ton	894,400	7.58
Soda ash	1,830 tons	90.00/ton	164,700	1.40
Total raw materials cost			1,059,100	8.98
Conversion costs				
Operating labor and supervision	31,900 man-hr	12.50/man-hr	398,800	3.38
Utilities				
Steam	415,500 MBtu	2.00/MBtu	831,000	7.05
Process water	167,900 kgal	0.12/kgal	29,200	0.17
Electricity	21,149,300 kWh	0.029/kWh	613,300	5.20
Maintenance				
Labor and material			1,670,100	14.16
Analyses	1,710 man-hr	17.00/man-hr	29,100	0.25
Total conversion costs			3,562,500	30.21
Total direct costs			4,621,600	39.19
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,455,700	20.82
Average cost of capital and taxes at 8.6% of total capital investment			3,627,400	30.76
Overheads				
Plant, 50% of conversion costs less utilities			1,049,000	8.89
Administrative, 10% of operating labor			39,900	0.34
Total indirect costs			7,172,000	60.81
Total average annual revenue requirements			11,793,600	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements	3.93	11.01	0.44	995

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 971,900 metric tons/yr (1,071,600 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 10,750 metric tons/yr (11,850 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $22,183,000; total depreciable investment, $40,929,000; and total capital investment, $42,179,000.
All tons shown are 2,000 lb.

TABLE C-13. DOUBLE-ALKALI SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 2.0% sulfur in coal; 90% SO_2 removal; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silos, and bin)	1,286,000	5.3
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	661,000	2.7
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,252,000	17.5
SO_2 absorption (four tray towers including presaturator and entrainment separators, recirculation tanks, agitators, and pumps)	9,451,000	38.8
Stack gas reheat (four indirect steam reheaters)	1,287,000	5.3
Reaction (tanks, agitators, and pumps)	286,000	1.2
Solids separation (thickener, drum filters, tanks, agitators, pumps, and conveyor)	1,928,000	7.9
Solids disposal (onsite disposal facilities including reslurry tank, agitator, slurry disposal pumps, and pond water return pumps)	1,023,000	4.2
Subtotal	20,174,000	82.9
Services, utilities, and miscellaneous	1,210,000	5.0
Total process areas excluding pond construction	21,384,000	87.9
Pond construction	2,950,000	12.1
Total direct investment	24,334,000	100.0
Indirect Investment		
Engineering design and supervision	1,366,000	5.6
Architect and engineering contractor	318,000	1.3
Construction expense	3,495,000	14.3
Contractor fees	1,086,000	4.5
Total indirect investment	6,265,000	25.7
Contingency	6,120,000	25.2
Total fixed investment	36,719,000	150.9
Other Capital Charges		
Allowance for startup and modifications	3,377,000	13.9
Interest during construction	4,406,000	18.1
Total depreciable investment	44,502,000	182.9
Land	578,000	2.4
Working capital	965,000	3.9
Total capital investment	46,045,000	189.2

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE C-14. DOUBLE-ALKALI SLUDGE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 2.0% sulfur in coal; 90% SO_2 removal; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	35,470 tons	40.00/ton	1,418,800	10.85
Soda ash	2,900 tons	90.00/ton	261,000	1.99
Total raw materials cost			1,679,800	12.84
Conversion costs				
Operating labor and supervision	31,900 man-hr	12.50/man-hr	398,800	3.05
Utilities				
Steam	417,400 MBtu	2.00/MBtu	834,800	6.38
Process water	179,300 kgal	0.12/kgal	21,500	0.16
Electricity	22,031,800 kWh	0.029/kWh	638,900	4.89
Maintenance				
Labor and material			1,719,600	13.15
Analyses	2,250 man-hr	17.00/man-hr	38,300	0.29
Total conversion costs			3,651,900	27.92
Total direct costs			5,331,700	40.76
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,670,100	20.41
Average cost of capital and taxes at 8.6% of total capital investment			3,959,900	30.27
Overheads				
Plant, 50% of conversion costs less utilities			1,078,400	8.25
Administrative, 10% of operating labor			39,900	0.31
Total indirect costs			7,748,300	59.24
Total average annual revenue requirements			13,080,000	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements	4.36	10.66	0.48	696

Basis

1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,113,200 metric tons/yr (1,227,300 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 17,040 metric tons/yr (18,790 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $24,334,000; total depreciable investment, $44,502,000; and total capital investment, $46,045,000.
All tons shown are 2,000 lb.

TABLE C-15. DOUBLE-ALKALI SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new lignite-fired power unit, 0.5% sulfur in lignite; 90% SO_2 removal; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silos, and bin)	553,000	2.7
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	347,000	1.7
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,414,000	21.3
SO_2 absorption (four tray towers including presaturator and entrainment separators, recirculation tanks, agitators, and pumps)	9,869,000	47.5
Stack gas reheat (four indirect steam reheaters)	1,341,000	6.4
Reaction (tanks, agitators, and pumps)	159,000	0.8
Solids separation (thickener, drum filters, tanks, agitators, pumps, and conveyor)	1,111,000	5.3
Solids disposal (onsite disposal facilities including reslurry tank, agitator, slurry disposal pumps, and pond water return pumps)	555,000	2.7
Subtotal	18,349,000	88.4
Services, utilities, and miscellaneous	1,101,000	5.3
Total process areas excluding pond construction	19,450,000	93.7
Pond construction	1,309,000	6.3
Total direct investment	20,759,000	100.0
Indirect Investment		
Engineering design and supervision	1,300,000	6.3
Architect and engineering contractor	312,000	1.5
Construction expense	3,099,000	14.9
Contractor fees	962,000	4.6
Total indirect investment	5,673,000	27.3
Contingency	5,286,000	25.5
Total fixed investment	31,718,000	152.8
Other Capital Charges		
Allowance for startup and modifications	3,041,000	14.7
Interest during construction	3,806,000	18.3
Total depreciable investment	38,565,000	185.8
Land	312,000	1.5
Working capital	718,000	3.4
Total capital investment	39,595,000	190.7

Basis
Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mi from power plant.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE C-16. DOUBLE-ALKALI SLUDGE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new lignite-fired power unit, 0.5% sulfur in lignite; 90% SO_2 removal; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	10,970 tons	40.00/ton	438,800	4.05
Soda ash	900 tons	90.00/ton	81,000	0.75
Total raw materials cost			519,800	4.80
Conversion costs				
Operating labor and supervision	31,900 man-hr	12.50/man-hr	398,800	3.68
Utilities				
Steam	441,000 MBtu	2.00/MBtu	882,000	8.15
Process water	167,800 kgal	0.12/kgal	20,100	0.19
Electricity	21,640,400 kWh	0.029/kWh	627,600	5.80
Maintenance				
Labor and material			1,595,300	14.73
Analyses	1,110 man-hr	17.00/man-hr	18,900	0.17
Total conversion costs			3,542,700	32.72
Total direct costs			4,062,500	37.52
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,313,900	21.37
Average cost of capital and taxes at 8.6% of total capital investment			3,405,200	31.45
Overheads				
Plant, 50% of conversion costs less utilities			1,006,500	9.29
Administrative, 10% of operating labor			39,900	0.37
Total indirect costs			6,765,500	62.48
Total average annual revenue requirements			10,828,000	100.00

	Mills/kWh	$/ton lignite burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements	3.61	6.34	0.40	1,863

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Lignite burned, 1,549,900 metric tons/yr (1,708,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 5,270 metric tons/yr (5,810 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $20,759,000; total depreciable investment, $38,565,000; and total capital investment, $39,595,000.
All tons shown are 2,000 lb.

TABLE C-17. DOUBLE-ALKALI SLUDGE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new oil-fired power unit, 2.5% sulfur in oil; 90% SO_2 removal; onsite solids disposal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silos, and bin)	1,146,000	5.4
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	606,000	2.9
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	3,770,000	17.8
SO_2 absorption (four tray towers including presaturator and entrainment separators, recirculation tanks, agitators, and pumps)	8,208,000	38.7
Stack gas reheat (four direct oil-fired reheaters)	1,127,000	5.3
Reaction (tanks, agitators, and pumps)	264,000	1.2
Solids separation (thickener, drum filters, tanks, agitators, pumps, and conveyor)	1,790,000	8.4
Solids disposal (onsite disposal facilities including reslurry tank, agitator, slurry disposal pumps, and pond water return pumps)	942,000	4.4
Subtotal	17,853,000	84.1
Services, utilities, and miscellaneous	1,071,000	5.0
Total process areas excluding pond construction	18,924,000	89.1
Pond construction	2,314,000	10.9
Total direct investment	21,238,000	100.0
Indirect Investment		
Engineering design and supervision	1,343,000	6.3
Architect and engineering contractor	316,000	1.5
Construction expense	3,131,000	14.8
Contractor fees	979,000	4.6
Total indirect investment	5,769,000	27.2
Contingency	5,401,000	25.4
Total fixed investment	32,408,000	152.6
Other Capital Charges		
Allowance for startup and modifications	3,009,000	14.2
Interest during construction	3,889,000	18.3
Total depreciable investment	39,306,000	185.1
Land	459,000	2.1
Working capital	894,000	4.2
Total capital investment	40,659,000	191.4

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by direct oil-fired reheat.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mi from power plant.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE C-18. DOUBLE-ALKALI SLUDGE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new oil-fired power unit, 2.5% sulfur in oil; 90% SO_2 removal; onsite solids disposal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Lime	30,240 tons	40.00/ton	1,209,600	10.18
Soda ash	2,470 tons	90.00/ton	222,300	1.87
Total raw materials cost			1,431,900	12.05
Conversion costs				
Operating labor and supervision	31,900 man-hr	12.50/man-hr	398,800	3.36
Utilities				
Fuel oil (No. 6)	2,425,900 gal	0.40/gal	970,400	8.17
Process water	150,500 kgal	0.12/kgal	18,100	0.15
Electricity	18,570,900 kWh	0.029/kWh	538,600	4.54
Maintenance				
Labor and material			1,583,300	13.33
Analyses	2,050 man-hr	17.00/man-hr	34,900	0.29
Total conversion costs			3,544,100	29.84
Total direct costs			4,976,000	41.89
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,358,400	19.85
Average cost of capital and taxes at 8.6% of total capital investment			3,496,700	29.43
Overheads				
Plant, 50% of conversion costs less utilities			1,008,500	8.49
Administrative, 10% of operating labor			39,900	0.34
Total indirect costs			6,903,500	58.11
Total average annual revenue requirements			11,879,500	100.00

	Mills/kWh	$/bbl oil burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements	3.96	2.66	0.44	741

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Oil burned, 710 x 10^6 liters/yr (4,464,300 bbl/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 14,530 metric tons/yr (16,020 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $21,238,000; total depreciable investment, $39,306,000; and total capital investment, $40,659,000.
All tons shown are 2,000 lb.

APPENDIX D

SEAWATER PROCESS

PROCESS DESCRIPTION

The seawater process, shown in Figure D-1, uses seawater from the power plant condensers as the scrubbing agent. Because the amount of condenser seawater is limited, the 3.5% and 2.0% sulfur coals are not included in the seawater process evaluation. The 149°C (300°F) flue gas is cooled to 53°C (127°F) in a presaturator and scrubbed in a countercurrent packed tower absorber to remove SO_2, SO_3, HCl, CO_2, and some residual fly ash. Seawater at 26°C (79°F) is used in both the presaturator and absorber in a one-pass flow. The flue gas is cooled to 27°C (81°F) in the SO_2 absorber.

Presaturator and absorber effluent at a pH of approximately 3.0 (based on SO_2 content only) is treated with additional condenser seawater to increase the pH to 6, treated with sparged air to oxidize 75% of the sulfite to sulfate, and returned to the sea. The chemical oxygen demand of the waste is estimated to be 3.1 mg O_2/liter or less. Reheat of the flue gas to 79°C (175°F) is included in the process. A case variation of reheat to 53°C (127°F) is also included.

The base-case material balance and equipment list are shown in Tables D-1 and D-2.

SPECIFIC PROCESS PREMISES

1. A packed-bed absorber with a presaturator and mist eliminator is used. Pressure drop in the unit is 1.05 kPa (4.2 inches H_2O) and the superficial velocity in the absorber is 1.8 m/sec (6 ft/sec).
2. The presaturator L/G ratio is 0.5 liter/m^3 (4 gal/10^3 aft^3) and the absorber L/G ratio is 8.0 liters/m^3 (60 gal/10^3 aft^3).
3. The total alkalinity of the seawater is assumed to be 2.4 meq/liter as $CaCO_3$.
4. Oxidation of SO_x to SO_4 is assumed to be 75% in the oxidation tank.
5. Only condenser seawater from the power plant is used for neutralization; no alkali or additional seawater is added.

ENERGY REQUIREMENTS

For base-case conditions, reheat of the cleaned gas from 27°C to 79°C requires 68.7 x 10^3 kg/hr (151,500 lb/hr) of 243°C (470°F) steam at 3.55 x 10^3 kPa absolute pressure (500 psig) equivalent to about 28.70 x 10^6 kcal/hr.

The electrical power demand for the seawater process, base case, is estimated to be about 7,012 kW or 1.4% of the rated capacity of a 500-MW power plant. For 6,000 hours of operation, the annual electrical energy consumption is 42.1 x 10^6 kWh.

The total equivalent energy consumption for the base case is approximately 47.79 x 10^6 kcal/hr or 4.2% of the input energy required for the 500-MW power unit. Summarized energy requirements for all cases are listed in Table D-3.

BYPRODUCT MANAGEMENT

ESP units remove 99.2% of the fly ash from the flue gas and, therefore, only a small amount of fly ash is found in the effluent which is pumped offshore for disposal. (Fly ash emission from oil-fired units does not exceed the EPA particulate emission standard and fly ash collection facilities are not included in oil-fired power plant design.) Projected mass flow rates of byproduct wastes for the base case are shown below.

Component	Kg/hr	Lb/hr
Total effluent	72,124,300	158,864,200
$SO_4^=$	4,040	8,900
$SO_3^=$	1,110	2,450
HCl	470	1,050
Fly ash	50	120

Approximate chemical oxygen demand (COD) for this effluent is estimated at 3.1 mg O_2/liter.

ECONOMIC EVALUATION

Capital investment and annual revenue requirements for the seawater process are summarized in Tables D-4 and D-5. Detailed results are shown in Tables D-6 through D-15. The accuracy ranges are shown graphically in Figures D-2 and D-3. The effect of sulfur content on these costs is shown in Figure D-4.

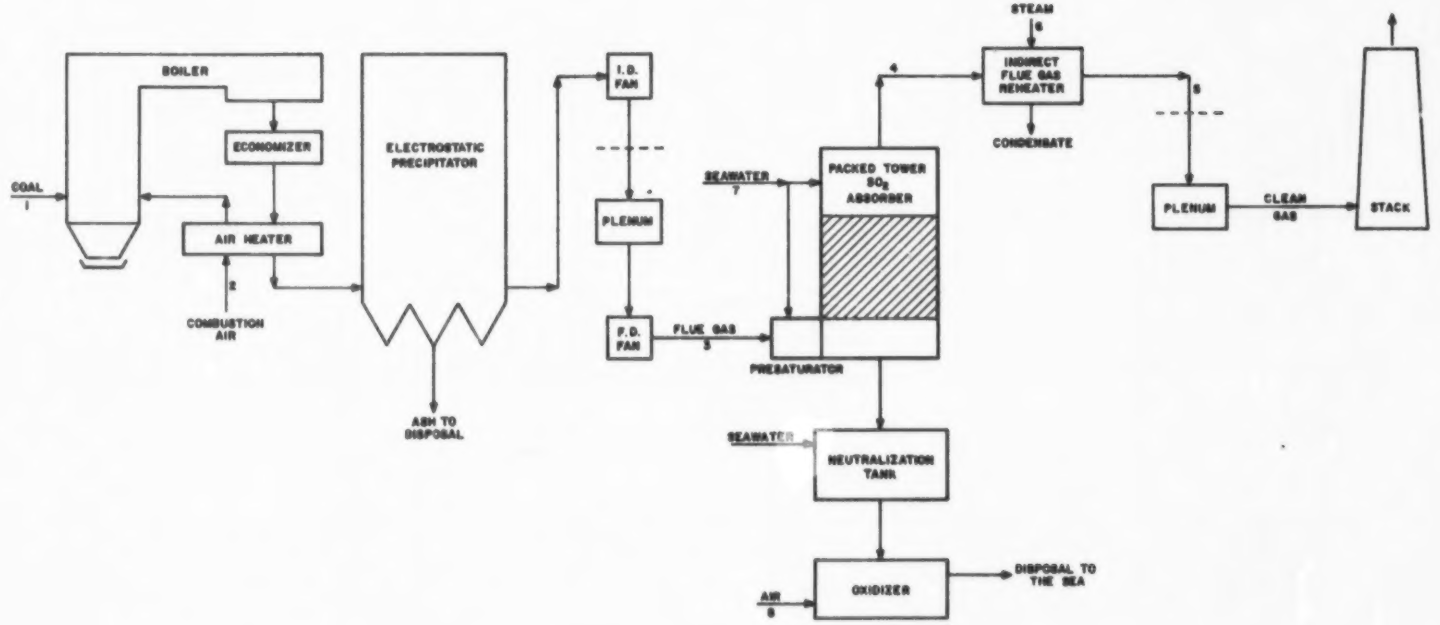
BOILER
COAL
1
ECONOMIZER
AIR HEATER
2
COMBUSTION AIR
ELECTROSTATIC PRECIPITATOR
ASH TO DISPOSAL
I.D. FAN
PLENUM
F.D. FAN
FLUE GAS
3
SEAWATER
7
PACKED TOWER
SO_2
ABSORBER
PRESATURATOR
4
STEAM
6
INDIRECT FLUE GAS REHEATER
CONDENSATE
5
PLENUM
CLEAN GAS
STACK
SEAWATER
NEUTRALIZATION TANK
AIR
8
OXIDIZER
DISPOSAL TO THE SEA

Figure D-1. Seawater process flow diagram.

TABLE D-1. SEAWATER PROCESS

MATERIAL BALANCE - BASE CASE (1.4% SULFUR COAL)

	Stream No.	1	2	3	4	5
	Description	Coal to boiler	Combustion air to air heater	Gas to presaturator-absorber	Gas to reheater	Gas to stack
1	Total stream, 1000 kg/hr	162	2060.8	2211.7	2151.5	2151.5
2	Total stream, lb/hr	357,200	4,543,200	4,876,000	4,743,300	4,743,300
3	Gas flow, Nm^3/hr (0^oC)		1,610,600	1,676,900	1,604,000	1,606,700
4	Gas flow, sft^3/min (60^oF)		1,001,900	1,043,300	997,800	999,500
5	Liquid flow, liters/min				35.8	
6	Liquid flow, gal/min				9.5	
7	Temperature, ^oC		26.7	148.9	27.2	79.4
8	Particulates, kg/hr			72.6	18.1	18.1
9	Particulates, lb/hr			160	40	40
10						

	Stream No.	6	7	8	9	10
	Description	Steam to reheater	Seawater to presaturator-absorber	Seawater to neutralizer	Air to oxidizer	Effluent to sea
1	Total stream, 1000 kg/hr	68.7	15,444.6	56,557	46.6	72,124
2	Total stream, lb/hr	151,500	34,049,700	124,683,900	102,800	158,864,200
3	Gas flow, Nm^3/hr (0^oC)				36,400	
4	Gas flow, sft^3/min (60^oF)				22,700	
5	Liquid flow, liters/min		255,020	933,280		1,190,170
6	Liquid flow, gal/min		67,370	246,790		314,440
7	Temperature, ^oC	243.3	26.1	26.1	26.7	26.1
8	Pressure, kPa (abs)	3.55×10^3				
9	Pressure, psig	500				
10						

1						
2						
3						
4						
5						
6						
7						
8						
9						
10						

1						
2						
3						
4						
5						
6						
7						
8						
9						
10						

TABLE D-2. SEAWATER PROCESS

BASE-CASE EQUIPMENT LIST
DESCRIPTION AND COST

Area 1--Materials Handling	Area size-cost exponent
No equipment in this area	

Area 2--Feed Preparation	Area size-cost exponent
No equipment in this area	

Area 3--Gas Handling — Area size-cost exponent 0.68

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Fan	4	Forced draft, 8.2 in. static head, 700 rpm, 800 hp, fluid drive, double width, double inlet	772,000	68,000
Subtotal			772,000	68,000

Area 4--SO_2 Absorption — Area size-cost exponent 0.80

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Absorber, SO_2	4	Packed tower, 38 ft long x 19 ft wide x 50 ft high, 1/4 in. carbon steel, neoprene lining, FRP internals, FRP chevron vane entrainment separator	3,496,000	300,000

(continued)

TABLE D-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
2. Pump, seawater	6	Centrifugal, 16,850 gpm, 70 ft head, 700 hp, carbon steel, neoprene lined (4 operating, 2 spare)	305,500	45,800
3. Soot blowers	40	Air, retractable	260,000	225,800
Subtotal			4,061,500	571,600

Area 5--Reheat — Area size-cost exponent 0.74

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Reheater	4	Steam, tube type, 5,580 ft^2, one-half tubes made of Inconel 625 and one-half made of Cor-Ten	1,123,900	56,600
2. Soot blowers	20	Air, retractable	130,000	112,900
Subtotal			1,253,900	169,500

Area 6--Neutralization — Area size-cost exponent 0.59

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Tank, neutralization	1	90 ft long x 8 ft wide x 25 ft high, 134,660 gal, open top, concrete (3 min residence time)	15,600	41,600
2. Pumps, neutralization tank	7	Vertical circulating, 49,360 gpm, 20 ft head, 400 hp, Al-bronze (5 operating, 2 spare)	1,050,000	200,000
Subtotal			1,065,600	241,600

(continued)

TABLE D-2 (continued)

Area 7--Oxidation and Disposal			Area size-cost exponent 0.68	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Tank, oxidation	4	22 ft dia x 21-1/2 ft high, 61,140 gal, open top, carbon steel (6 min residence time)	40,700	73,000
Lining		1/4 in. neoprene lining	33,600	41,100
2. Blower, oxidation air	2	Two-stage centrifugal, 11,340 sft^3/min, 700 hp, 316 SS	345,200	3,000
Subtotal			419,500	117,100

TABLE D-3. SEAWATER PROCESS ENERGY REQUIREMENTS

Case	Reheat, kcal/hr	Electricity, kcal/hr (kW)	Process steam, kcal/hr	Oil, kcal/hr	Natural gas, kcal/hr	Total equivalent energy consumption,[a] % of input energy
500-MW unit						
Coal, 1.4% sulfur (base case)	28.70 M	15.91 M (7,012)	-	-	-	4.22
Coal, 0.8% sulfur	29.69 M	14.89 M (6,563)	-	-	-	4.22
Lignite, 0.5% sulfur	30.46 M	13.88 M (6,119)	-	-	-	4.21
Oil, 2.5% sulfur	24.13 M	15.47 M (6,823)	-	-	-	3.49
Coal, 1.4% sulfur (low-temperature alternate)[b]	14.46 M	15.91 M (7,012)	-	-	-	2.82

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[a] Based on a boiler efficiency of 90% for generation of steam and a gross heat rate of 9,000 Btu/kWh for generation of electricity.

[b] Based on stack gas reheat to 53°C (127°F).

TABLE D-4. SEAWATER PROCESS CAPITAL INVESTMENT

Case	Total capital investment $	 $/kW
500-MW unit		
Coal, 1.4% sulfur (base case)	30,048,000	60
Coal, 0.8% sulfur	29,590,000	59
Lignite, 0.5% sulfur	29,068,000	58
Oil, 2.5% sulfur	27,937,000	56
Coal, 1.4% sulfur (low-temperature alternate)	28,582,000	57

TABLE D-5. SEAWATER PROCESS ANNUAL REVENUE REQUIREMENTS

Case	$	Mills/kWh	$/ton coal (bbl oil) burned	$/MBtu heat input	$/ton S removed
500-MW unit					
Coal, 1.4% S (base case)	8,707,100	2.90	8.13	0.32	735
Coal, 0.8% S	8,667,100	2.89	6.10	0.32	1,086
Lignite, 0.5% S	8,516,800	2.84	4.98	0.32	1,466
Oil, 2.5% S	8,575,600	2.86	1.92	0.32	535
Coal, 1.4% S (low-temperature alternate)	7,837,700	2.61	7.31	0.29	661

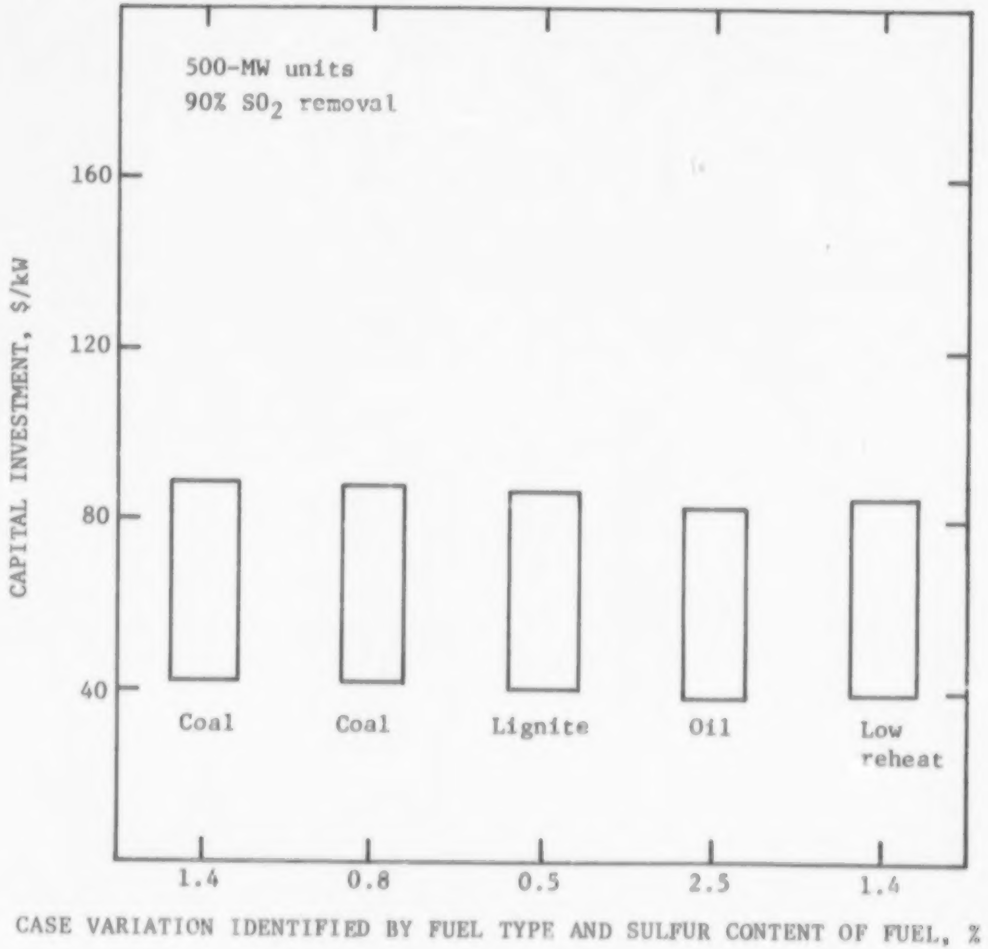

Figure D-2. Seawater process capital investment range.

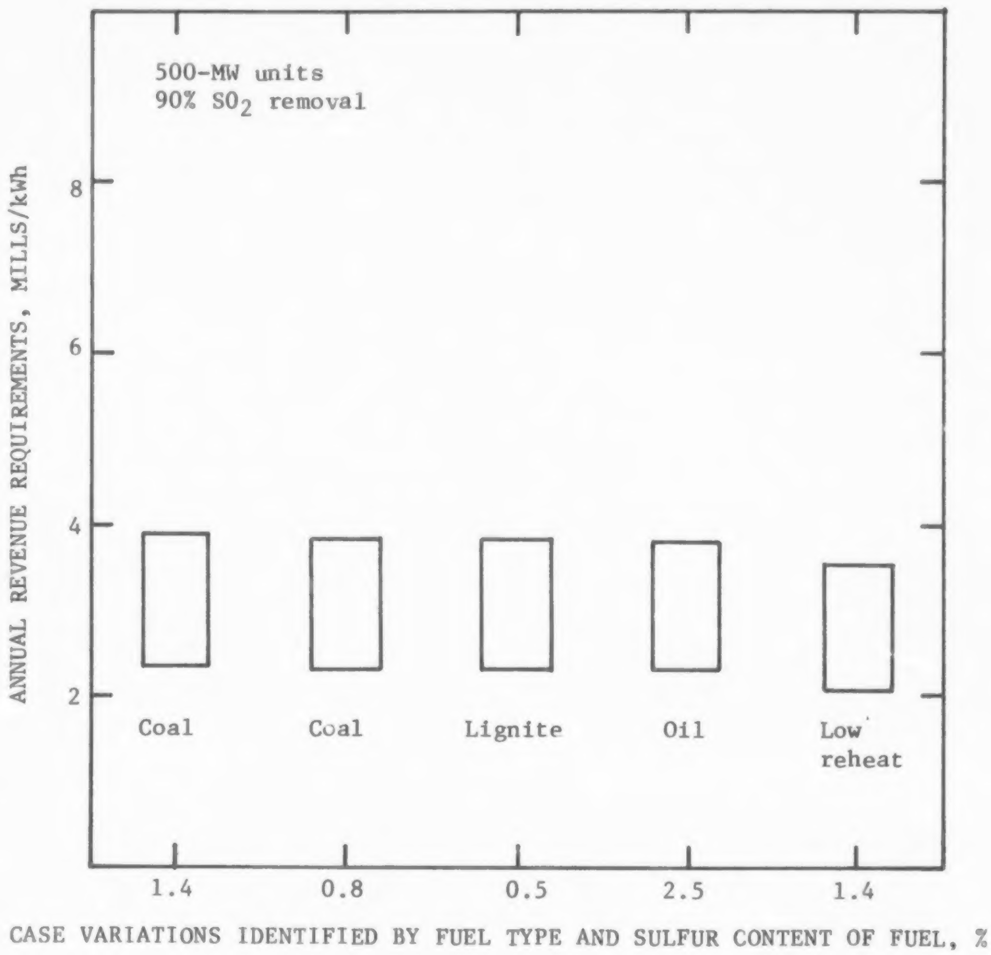

Figure D-3. Seawater process annual revenue requirements range.

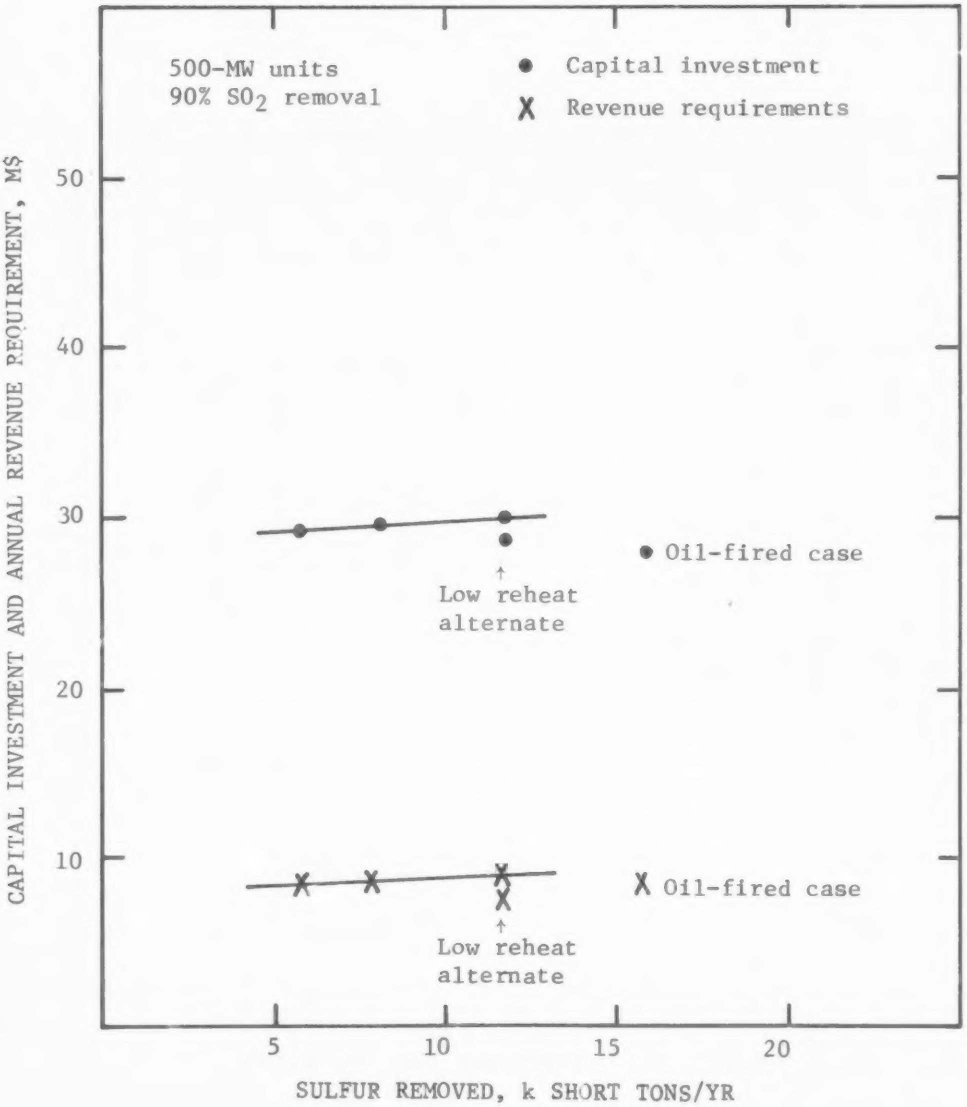

Figure D-4. Seawater process. Effect of sulfur removed on capital investment and annual revenue requirement.

TABLE D-6. SEAWATER PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new, coal-fired power unit,
1.4% sulfur in coal, 90% SO_2 removal)

	Investment, $	% of total direct investment
Direct Investment		
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to reactor, exhaust gas ducts and dampers from absorber to reheater and stack)	3,519,000	21.6
SO_2 absorption (four absorbers including entrainment separators and seawater pumps)	7,069,000	43.4
Reheat (four indirect steam reheaters)	1,594,000	9.8
Neutralization (tanks, agitators, and pumps)	2,367,000	14.5
Oxidation and disposal (tanks and air compressor)	815,000	5.0
Subtotal direct investment	15,364,000	94.3
Services, utilities, and miscellaneous	922,000	5.7
Total direct investment	16,286,000	100.0
Indirect Investment		
Engineering design and supervision	392,000	2.4
Architect and engineering contractor	98,000	0.6
Construction expense	2,534,000	15.6
Contractor fees	800,000	4.9
Total indirect investment	3,824,000	23.5
Contingency	4,022,000	24.7
Total fixed investment	24,132,000	148.2
Other Capital Charges		
Allowance for startup and modification	2,413,[illegible]00	14.8
Interest during construction	2,896,000	17.8
Total depreciable investment	29,441,000	180.8
Land	21,000	0.1
Working capital	586,000	3.6
Total capital investment	30,048,000	184.5

Basis
- Plant represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
- Stack gas reheat to 79°C (175°F) by indirect steam reheat.
- Only pumps are spared.
- Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
- Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE D-7. SEAWATER PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new, coal-fired power unit,
1.4% sulfur in coal, 90% SO_2 removal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Conversion costs				
Operating labor and supervision	17,520 man-hr	12.50/man-hr	219,000	2.52
Utilities				
Steam	638,200 MBtu	2.00/MBtu	1,276,400	14.66
Electricity	42,074,400 kWh	0.029/kWh	1,220,200	14.01
Maintenance				
Labor and material			977,200	11.22
Analyses	1,710 man-hr	17.00/man-hr	29,100	0.33
Total conversion costs			3,721,900	42.74
Total direct costs			3,721,900	42.74
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			1,766,500	20.29
Average cost of capital and taxes at 8.6% of total capital investment			2,584,100	29.68
Overheads				
Plant, 50% of conversion costs less utilities			612,700	7.04
Administrative, 10% of operating labor			21,900	0.25
Total indirect costs			4,985,200	57.26
Total average annual revenue requirements			8,707,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements	2.90	8.13	0.32	735

Basis
- 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 6,000 hr/yr.
- Coal burned, 971,941 metric tons/yr (1,071,600 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
- Stack gas reheat to 79°C (175°F).
- Sulfur removed, 10,748 metric tons/yr (11,850 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $16,286,000; total depreciable investment, $29,441,000; and total capital investment, $30,048,000.

TABLE D-8. SEAWATER PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new, coal-fired power unit, 0.8% sulfur in coal, 90% SO_2 removal)

	Investment, $	% of total direct investment
Direct Investment		
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to reactor, exhaust gas ducts and dampers from absorber to reheater and stack)	3,600,000	22.5
SO_2 absorption (four absorbers including entrainment separators and seawater pumps)	7,267,000	45.4
Reheat (four indirect steam reheaters)	1,636,000	10.2
Neutralization (tanks, agitators, and pumps)	1,953,000	12.2
Oxidation and disposal (tanks, agitators, pumps, and air compressor)	653,000	4.1
Subtotal direct investment	15,109,000	94.4
Services, utilities, and miscellaneous	907,000	5.6
Total direct investment	16,016,000	100.0
Indirect Investment		
Engineering design and supervision	392,000	2.5
Architect and engineering contractor	98,000	0.6
Construction expense	2,499,000	15.6
Contractor fees	790,000	4.9
Total indirect investment	3,779,000	23.6
Contingency	3,959,000	24.7
Total fixed investment	23,754,000	148.3
Other Capital Charges		
Allowance for startup and modification	2,375,000	14.8
Interest during construction	2,850,000	17.8
Total depreciable investment	28,979,000	180.9
Land	21,000	0.1
Working capital	590,000	3.7
Total capital investment	29,590,000	184.7

Basis

Plant represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE D-9. SEAWATER PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new, coal-fired power unit,
0.8% sulfur in coal, 90% SO_2 removal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Conversion costs				
Operating labor and supervision	17,520 man-hr	12.50/man-hr	219,000	2.53
Utilities				
Steam	706,900 MBtu	2.00/MBtu	1,413,800	16.30
Electricity	39,378,100 kWh	0.029/kWh	1,142,000	13.18
Maintenance				
Labor and material			961,000	11.09
Analyses	1,410 man-hr	17.00/man-hr	24,000	0.28
Total conversion costs			3,759,800	43.38
Total direct costs			3,759,800	43.38
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			1,738,700	20.06
Average cost of capital and taxes at 8.6% of total capital investment			2,544,700	29.36
Overheads				
Plant, 50% of conversion costs less utilities			602,000	6.95
Administrative, 10% of operating labor			21,900	0.25
Total indirect costs			4,907,300	56.62
Total average annual revenue requirements			8,667,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements	2.89	6.10	0.32	1,086

Basis
- 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 6,000 hr/yr.
- Coal burned, 1,288,938 metric tons/yr (1,421,100 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
- Stack gas reheat to 79°C (175°F).
- Sulfur removed, 7,238 metric tons/yr (7,980 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $16,016,000; total depreciable investment, $28,979,000; and total capital investment, $29,590,000.

TABLE D-10. SEAWATER PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new, lignite-fired power unit,
0.5% sulfur in lignite, 90% SO_2 removal)

	Investment, $	% of total direct investment
Direct Investment		
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to reactor, exhaust gas ducts and dampers from absorber to reheater and stack)	3,663,000	23.3
SO_2 absorption (four absorbers including entrainment separators and seawater pumps)	7,415,000	47.2
Reheat (four indirect steam reheaters)	1,667,000	10.6
Neutralization (tanks, agitators, and pumps)	1,572,000	10.0
Oxidation and disposal (tanks, agitators, pumps, and air compressor)	509,000	3.2
Subtotal direct investment	14,826,000	94.3
Services, utilities, and miscellaneous	890,000	5.7
Total direct investment	15,716,000	100.0
Indirect Investment		
Engineering design and supervision	392,000	2.5
Architect and engineering contractor	98,000	0.6
Construction expense	2,460,000	15.7
Contractor fees	779,000	5.0
Total indirect investment	3,729,000	23.7
Contingency	3,889,000	24.7
Total fixed investment	23,334,000	148.5
Other Capital Charges		
Allowance for startup and modification	2,333,000	14.9
Interest during construction	2,800,000	17.8
Total depreciable investment	28,467,000	181.1
Land	21,000	0.1
Working capital	580,000	3.7
Total capital investment	29,068,000	185.0

Basis

Plant represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE D-11. SEAWATER PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new, lignite-fired power unit,
0.5% sulfur in lignite, 90% SO_2 removal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Conversion costs				
Operating labor and supervision	17,520 man-hr	12.50/man-hr	219,000	2.57
Utilities				
Steam	725,200 MBtu	2.00/MBtu	1,450,400	17.03
Electricity	36,716,500 kWh	0.029/kWh	1,064,800	12.50
Maintenance				
Labor and material			943,000	11.07
Analyses	1,130 man-hr	17.00/man-hr	19,200	0.23
Total conversion costs			3,696,400	43.40
Total direct costs			3,696,400	43.40
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			1,708,000	20.05
Average cost of capital and taxes at 8.6% of total capital investment			2,499,900	29.35
Overheads				
Plant, 50% of conversion costs less utilities			590,600	6.92
Administrative, 10% of operating labor			21,900	0.28
Total indirect costs			4,820,400	56.60
Total average annual revenue requirements			8,516,800	100.00

	Mills/kWh	$/ton lignite burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements	2.84	4.98	0.32	1,466

Basis
- 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 6,000 hr/yr.
- Lignite burned, 1,549,882 metric tons/yr (1,708,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
- Stack gas reheat to 79°C (175°F).
- Sulfur removed, 5,270 metric tons/yr (5,810 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $15,716,000; total depreciable investment, $28,467,000; and total capital investment, $29,068,000.

TABLE D-12. SEAWATER PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new, oil-fired power unit,
2.5% sulfur in oil, 90% SO_2 removal)

	Investment, $	% of total direct investment
Direct Investment		
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to reactor, exhaust gas ducts and dampers from absorber to reheater and stack)	3,128,000	20.8
SO_2 absorption (four absorbers including entrainment separators and seawater pumps)	6,157,000	41.0
Reheat (four direct oil-fired reheaters)	1,404,000	9.3
Neutralization (tanks, agitators, and pumps)	2,592,000	17.2
Oxidation and disposal (tanks, agitators, pumps, and air compressor)	906,000	6.0
Subtotal direct investment	14,187,000	94.3
Services, utilities, and miscellaneous	851,000	5.7
Total direct investment	15,038,000	100.0
Indirect Investment		
Engineering design and supervision	392,000	2.6
Architect and engineering contractor	98,000	0.6
Construction expense	2,371,000	15.8
Contractor fees	753,000	5.0
Total indirect investment	3,614,000	24.0
Contingency	3,730,000	24.8
Total fixed investment	22,382,000	148.8
Other Capital Charges		
Allowance for startup and modification	2,238,000	14.9
Interest during construction	2,686,000	17.9
Total depreciable investment	27,306,000	181.6
Land	21,000	0.1
Working capital	610,000	4.1
Total capital investment	27,937,000	185.8

Basis

Plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by direct oil-fired reheat.

Only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE D-13. SEAWATER PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new, oil-fired power unit,
2.5% sulfur in oil, 90% SO_2 removal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Conversion costs				
Operating labor and supervision	17,520 man-hr	12.50/man-hr	219,000	2.55
Utilities				
Fuel oil (No. 6)	3,988,900 gal	0.40/gal	1,595,600	18.61
Electricity	40,935,200 kWh	0.029/kWh	1,187,100	13.84
Maintenance				
Labor and material			902,300	10.52
Analyses	1,880 man-hr	17.00/man-hr	32,000	0.37
Total conversion costs			3,936,000	45.89
Total direct costs			3,936,000	45.89
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			1,638,400	19.11
Average cost of capital and taxes at 8.6% of total capital investment			2,402,600	28.02
Overheads				
Plant, 50% of conversion costs less utilities			576,700	6.72
Administrative, 10% of operating labor			21,900	0.26
Total indirect costs			4,639,600	54.11
Total average annual revenue requirements			8,575,600	100.00

	Mills/kWh	$/bbl oil burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements	2.86	1.92	0.32	535

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr
Oil burned, 710 x 10^6 liters (4,464,300 bbl/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 14,530 metric tons/yr (16,020 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $15,038,000; total depreciable investment, $27,306,000; and total capital investment, $27,937,000.

TABLE D-14. SEAWATER PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new, coal-fired power unit, 1.4% sulfur in coal, 90% SO_2 removal, low reheat temperature)

	Investment, $	% of total direct investment
Direct Investment		
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to reactor, exhaust gas ducts and dampers from absorber to reheater and stack)	3,519,000	22.7
SO_2 absorption (four absorbers including entrainment separators and seawater pumps)	7,069,000	45.7
Reheat (four indirect steam reheaters)	834,000	5.4
Neutralization (tanks, agitators, and pumps)	2,367,000	15.3
Oxidation and disposal (tanks, agitators, pumps, and air compressor)	815,000	5.2
Subtotal direct investment	14,604,000	94.3
Services, utilities, and miscellaneous	876,000	5.7
Total direct investment	15,480,000	100.0
Indirect Investment		
Engineering design and supervision	392,000	2.5
Architect and engineering contractor	98,000	0.6
Construction expense	2,429,000	15.7
Contractor fees	770,000	5.0
Total indirect investment	3,689,000	23.8
Contingency	3,834,000	24.8
Total fixed investment	23,003,000	148.6
Other Capital Charges		
Allowance for startup and modification	2,300,000	14.9
Interest during construction	2,760,000	17.8
Total depreciable investment	28,063,000	181.3
Land	21,000	0.1
Working capital	498,000	3.2
Total capital investment	28,582,000	184.6

Basis

Plant represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 53°C (127°F) by indirect steam reheat.

Only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE D-15. SEAWATER PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new, coal-fired power unit, 1.4% sulfur
in coal, 90% SO_2 removal, low reheat temperature)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Conversion costs				
Operating labor and supervision	17,520 man-hr	12.50/man-hr	219,000	2.79
Utilities				
Steam	344,200 MBtu	2.00/MBtu	688,400	8.78
Electricity	42,074,400 kWh	0.029/kWh	1,220,200	15.57
Maintenance				
Labor and material			928,800	11.85
Analyses	1,710 man-hr	17.00/man-hr	29,100	0.37
Total conversion costs			3,085,500	39.36
Total direct costs			3,085,500	39.36
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			1,683,800	21.48
Average cost of capital and taxes at 8.6% of total capital investment			2,458,000	31.36
Overheads				
Plant, 50% of conversion costs less utilities			588,500	7.52
Administrative, 10% of operating labor			21,900	0.28
Total indirect costs			4,752,200	60.69
Total average annual revenue requirements			7,837,700	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements	2.61	7.31	0.29	661

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 971,941 metric tons/yr (1,071,600 tons/hr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 53°C (127°F).
Sulfur removed, 10,748 metric tons/yr (11,850 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $15,480,000; total depreciable investment, $28,063,000; and total capital investment, $28,582,000.

APPENDIX E

LIME GYPSUM PROCESS

(SAARBERG-HÖLTER PROCESS)

PROCESS DESCRIPTION

The Saarberg-Hölter process, shown in Figure E-1, removes SO_2 using a clear alkaline scrubbing solution in a ROTOPART, a patented modular-design absorber. The flue gas enters the ROTOPART vessel at 149°C (300°F) and is adiabatically cooled to 53°C (127°F) by contact with clear scrubbing solution. The flue gas and the scrubbing solution are cocurrently contacted in vertical scrubbing tubes of the ROTOPART vessel. The scrubbing tubes have no packing but are equipped with injection nozzles and special shedding rings to promote liquid-gas contact. SO_2, SO_3, HCl, and some residual fly ash are removed from the gas stream. Gas and washing fluid are centrifugally separated in the separator section of the ROTOPART vessel. No further demisting is required.

SO_2 in the flue gas reacts with $CaCl_2$ and $Ca(OH)_2$ in the scrubbing solution to form soluble $Ca(HSO_3)_2$ and HCl. The system uses formic acid as a buffering agent to maintain a pH of about 4.5. The acidic absorber effluent flows by gravity to an oxidizer vessel where air blown through the liquid oxidizes $Ca(HSO_3)_2$ to $CaSO_4 \cdot 2H_2O$ and H_2SO_4. $Ca(OH)_2$ is added at the oxidizer to neutralize the liquid and to replenish calcium in the solution. Makeup formic acid is also added at the oxidizer.

Oxidizer effluent is pumped to a thickener where the suspension of $CaSO_4 \cdot 2H_2O$ crystals is thickened to a 15% solids slurry. Slurry from the thickener is filtered to produce an 80% solids cake. The filter cake is conveyed to a storage area. Filtrate is recycled to the thickener and thickener overflow at a pH of 10.5 is returned to the absorber for use as scrubbing liquid.

The base-case material balance and equipment list are shown in Tables E-1 and E-2.

SPECIFIC PROCESS PREMISES

1. The ROTOPART has a superficial velocity of 12.2 m/sec (40 ft/sec) in the scrubber tubes and a pressure drop through the unit of 2.44 kPa (9.8 inches H_2O). The L/G ratio is proprietary.

2. The stoichiometry of 1.01 moles of CaO to 1.00 mole of SO_2 removed and 1.0 mole of CaO to 2.0 moles of HCl removed.

3. Complete oxidation of SO_2 removed to sulfate in the form of gypsum is assumed.

ENERGY REQUIREMENTS

For base-case conditions, reheat of the cleaned gas from 53°C to 79°C requires 42.4×10^3 kg/hr (93,460 lb/hr) of 243°C (470°F) steam at 3,550 kPa absolute pressure (500 psig), equivalent to about 17.7×10^6 kcal/hr.

The electrical power demand for the base-case lime gypsum process is about 9701 kW or 1.9% of the rated output of a 500-MW power plant. For 6000 hours of operation, the annual electrical energy consumption is 58.2×10^6 kWh.

The total equivalent energy consumption for the base case is approximately 39.70×10^6 kcal/hr or 3.7% of the input energy required for the 500-MW power unit. Summarized energy requirements for all cases are listed in Table E-3.

BYPRODUCT MANAGEMENT

Electrostatic precipitators remove 99.2% of the fly ash from the flue gas and, therefore, only a small amount of fly ash is found in the FGD process byproduct. (Fly ash emission from oil-fired units does not exceed the EPA particulate emission standard and fly ash collection facilities are not included in oil-fired power plant design.) Projected mass flow rates of byproduct for the base case are shown below.

Component	Kg/hr	Lb/hr
$CaSO_4 \cdot 2H_2O$	27,640	60,880
$CaSO_3 \cdot 1/2H_2O$	82	180
$CaCl_2$	440	968
$Mg(OH)_2$	295	650
Fly ash	149	329
Inerts	102	225
	28,708	63,232

The process is evaluated on the basis of 30-day storage of gypsum byproduct. A 0.4 hectare (1 acre) storage area has been provided for the base case and all fuel variations.

ECONOMIC EVALUATION

Capital investment and annual revenue requirements for the base case and five fuel variations are shown in Tables E-4 and E-5. The detailed results are shown in Tables E-6 through E-17. The estimated accuracy ranges of the economic analysis are shown in Figures E-2 and E-3. The effect of fuel sulfur content on costs is shown in Figure E-4.

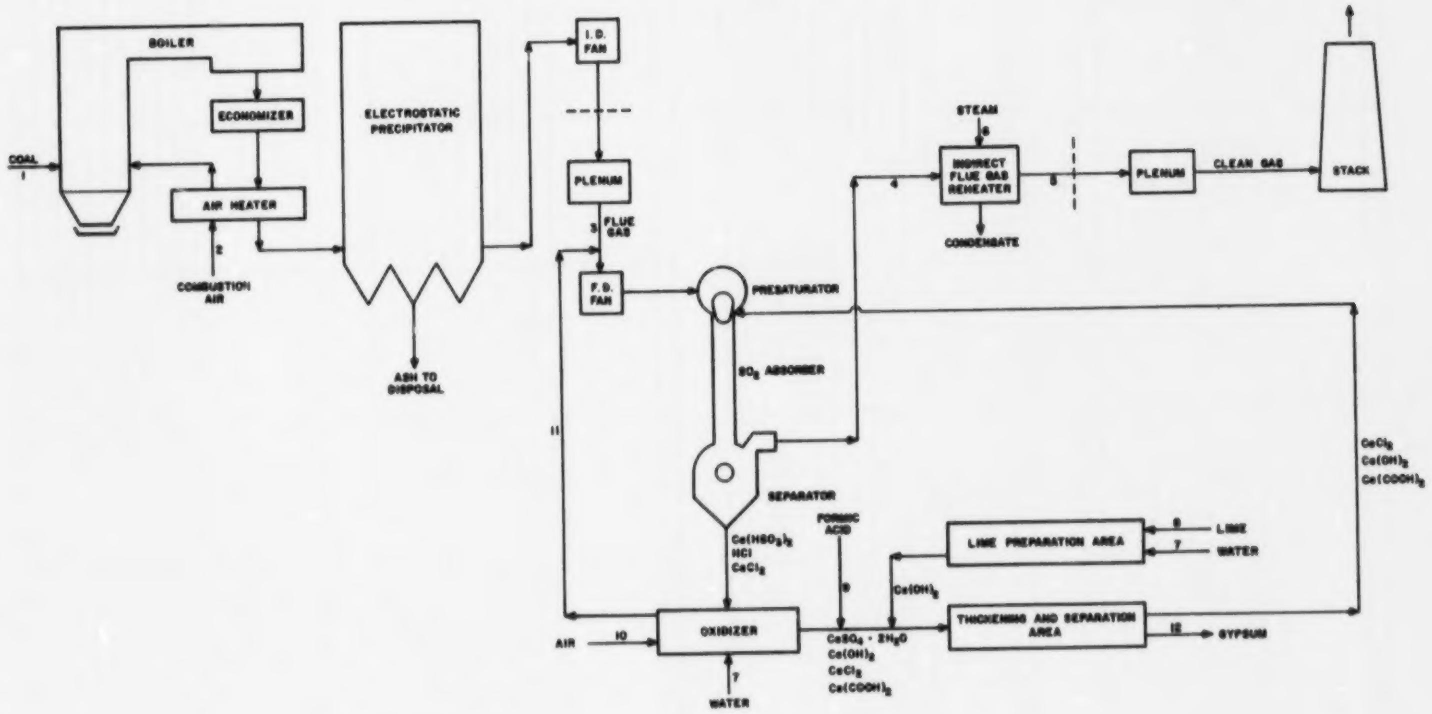
BOILER
COAL
1
ECONOMIZER
AIR HEATER
2
COMBUSTION AIR
ELECTROSTATIC PRECIPITATOR
ASH TO DISPOSAL
I. D. FAN
PLENUM
3
FLUE GAS
F. D. FAN
11
PRESATURATOR
SO_2 ABSORBER
SEPARATOR
$Ca(HSO_3)_2$
HCl
$CaCl_2$
AIR
10
OXIDIZER
7
WATER
FORMIC ACID
9
$CaSO_4 \cdot 2H_2O$
$Ca(OH)_2$
$CaCl_2$
$Ca(COOH)_2$
LIME PREPARATION AREA
8
LIME
7
WATER
THICKENING AND SEPARATION AREA
12
GYPSUM
$CaCl_2$
$Ca(OH)_2$
$Ca(COOH)_2$
4
STEAM
6
INDIRECT FLUE GAS REHEATER
CONDENSATE
5
PLENUM
CLEAN GAS
STACK

Figure E-1. Saarberg-Hölter process flow diagram.

TABLE E-1. SAARBERG-HOLTER PROCESS

MATERIAL BALANCE - BASE CASE (3.5% S COAL)

Stream No.		1	2	3	4	5
Description		Coal to boiler	Combustion air to air heater	Gas to absorber	Gas to reheater	Gas to stack
1	Total stream, 1000 kg/hr	194	2,062	2,225	2,428	2,428
2	Total stream, lb/hr	428,600	4,546,200	4,906,000	5,352,900	5,352,900
3	Gas flow, Nm^3/hr (0°C)		1,615,700	1,697,700	1,903,200	1,906,200
4	Gas flow, sft^3/min (60°F)		1,005,000	1,056,000	1,183,900	1,185,800
5	Liquid flow, liters/min				40.4	
6	Liquid flow, gal/min				10.7	
7	Temperature, $^\circ$C		27	149	53	79
8	Particulates, kg/hr			199	50	50
9	Particulates, lb/hr			439	110	110
10						

Stream No.		6	7	8	9	10
Description		Steam to reheater	Process makeup water	Lime to system	Formic acid	Oxidation air
1	Total stream, 1000 kg/hr	42	216	10	7.9 x 10^{-3}	56.4
2	Total stream, lb/hr	93,500	475,300	21,200	17.3	124,200
3	Gas flow, Nm^3/hr (0°C)					44,000
4	Gas flow, sft^3/min (60°F)					27,400
5	Liquid flow, liters/min		3,600			
6	Liquid flow, gal/min		950			
7	Temperature, $^\circ$C	243				
8	Pressure, Pascals (abs)	3.55 x 10^6				
9	Pressure, psig	500				
10						

Stream No.		11	12			
Description		Oxidizer off-gas	Gypsum			
1	Total stream, 1000 kg/hr	58.4	35			
2	Total stream, lb/hr	128,700	77,800			
3	Liquid flow, liters/min					
4	Liquid flow, gal/min					
5	Undissolved solids, %		80			
6	Particulates, kg/hr					
7	Particulates, lb/hr					
8	Bulk density, kg/m^3		1,360			
9	Bulk density, lb/ft^3		85			
10						

1						
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TABLE E-2. SAARBERG-HÖLTER PROCESS

BASE-CASE EQUIPMENT LIST
DESCRIPTION AND COST

Area 1--Materials Handling			Area size-cost exponent 0.74	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Conveyor, lime storage (enclosed)	1	Belt, 24 in. wide x 1,500 ft long, 30 hp, 100 tons/hr, 150 ft/min	155,800	52,300
2. Elevator, lime storage	1	Continuous, bucket 16 in. x 8 in. x 11-3/4 in., 75 hp, 120 ft lift, 100 tons/hr, 160 ft/min	102,900	2,400
3. Silo, lime storage	1	50 ft dia x 74 ft straight side, 145,300 ft^3, 60° slope, 3/8 in. carbon steel	88,400	246,100
4. Feeder, reclaim	1	Vibrating pan, 3-1/2 hp, 40 tons/hr	12,200	2,100
5. Conveyor, live lime feed (enclosed)	1	Belt, 18 in. wide x 100 ft long, 2 hp, 40 tons/hr, 100 ft/min	23,400	4,800
6. Elevator, live lime feed	1	Continuous, bucket 11 in. x 6 in. x 8-3/4 in., 50 hp, 50 ft lift, 40 tons/hr, 160 ft/min, with diverter gate	56,000	1,100
7. Bin, lime feed	2	10 ft dia x 15 ft high, w/cover, carbon steel	5,400	11,300
8. Dust collecting system	1	Bag filter, polypropylene bag, 8,800 aft^3/min, 7-1/2 hp, automatic shaker system (1/2 cost in feed preparation area)	10,700	28,200
Subtotal			454,800	348,300

(continued)

TABLE E-2 (continued)

Area 2--Feed Preparation			Area size-cost exponent 0.55	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Feeder, lime bin discharge	2	Vibrating, 3-1/2 hp	9,200	3,700
2. Feeder, slaker weigh	2	Screw, 12 in. dia x 12 ft long slaker, 1 hp, 6 tons/hr	12,000	1,400
3. Slaker	2	7 ft wide x 31 ft long, 10 hp, 2 hp clarifier, 6 tons/hr	116,300	12,100
4. Tank, slaker product	2	4 ft dia x 4 ft high, 380 gal, open top, four 4 in. baffles, agitator supports, carbon steel (10 min residence time)	700	1,300
Lining		1/4 in. neoprene lining	800	1,000
5. Agitator, slaker product tank	2	Two turbines, 16 in. dia, 1-1/2 hp, neoprene coated	7,600	2,200
6. Pump, slaker product tank	3	Centrifugal, 31 gpm, 60 ft head, 2 hp, carbon steel, neoprene lined (2 operating, 1 spare)	5,100	1,800
7. Tank, slurry feed	1	18 ft dia x 17-1/2 ft high, 33,300 gal, open top, four 18 in. baffles, agitator supports, carbon steel (8 hr residence time)	7,000	12,600
Lining		1/4 in. neoprene lining	7,200	8,800
8. Agitator, slurry feed tank	1	Two turbines, 72 in. dia, 30 hp, neoprene coated	33,100	2,100
9. Pump, slurry feed tank	2	Centrifugal, 62 gpm, 60 ft head, 5 hp, carbon steel, neoprene lined (1 operating, 1 spare)	3,800	1,200

(continued)

TABLE E-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
10. Dust collecting system	1	Bag filter, polypropylene bag, 8,800 aft^3/min, 7-1/2 hp, automatic shaker system (1/2 cost in material handling)	10,700	28,200
Subtotal			213,500	76,400

Area 3--Gas Handling

Area size-cost exponent 0.68

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Fans	4	Forced draft, 13.8 in. static head, 875 rpm, 1,250 hp, fluid drive, double width, double inlet	1,427,900	93,100
Subtotal			1,427,900	93,100

Area 4--SO_2 Absorption

Area size-cost exponent 0.93

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. SO_2 absorber	4	ROTOPART, length 80 ft, 4 washing ducts (dia - 6 ft 4 in.), 7 cast iron spray nozzles/duct, capacity - 395,000 aft^3/min	2,236,000	210,000
2. Pump, absorber feed	12	Proprietary (8 operating, 4 spares)	555,500	70,700
3. Soot blowers	40	Air, retractable	260,000	225,800
Subtotal			3,051,500	506,500

(continued)

TABLE E-2 (continued)

Area 5--Reheat			Area size-cost exponent 0.75	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Reheater	4	Steam, tube type, 3,770 ft^2, one-half tubes made of Inconel 625 and one-half made of Cor-Ten	858,000	41,200
2. Soot blowers	20	Air, retractable	130,000	112,900
Subtotal			988,000	154,100

Area 6--Oxidation			Area size-cost exponent 0.78	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Oxidation vessel	4	43 ft dia x 43 ft high, 464,280 gal, covered, carbon steel	430,700	345,900
Lining		Epoxy lined	172,500	210,900
2. Blower, oxidation air	4	Three-stage centrifugal, 6,850 sft^3/min, 600 hp, 316 stainless steel	439,200	63,200
3. Pump, oxidizer drain	4	Centrifugal, 225 gpm, 50 ft head, 10 hp, carbon steel (2 operating, 2 spares)	15,400	3,000
4. Pump, makeup water	4	Centrifugal, 455 gpm, 75 ft head, 20 hp, carbon steel (2 operating, 2 spares)	17,100	5,900
Subtotal			1,074,900	628,900

(continued)

TABLE E-2 (continued)

Area 7--Thickening and Solids Separation and Storage				Area size-cost exponent 0.47	
	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1.	Thickener	2	Concrete construction, 130 ft dia x 33 ft high, 3,275,000 gal, concrete basin, 4 ft high	488,400	1,196,000
	Rake and motor mechanism		7-1/2 hp	799,600	266,600
2.	Pump, thickener underflow	4	Centrifugal, 370 gpm, 60 ft head, 15 hp, carbon steel, neoprene lined (2 operating, 2 spares)	16,200	5,900
3.	Filter	2	Rotary, vacuum, 11-1/2 ft dia x 14 ft face, 20 total hp	256,300	26,800
4.	Pump, filtrate	4	Centrifugal, 320 gpm, 60 ft head, 15 hp, carbon steel, neoprene lined (2 operating, 2 spares)	16,200	5,900
5.	Conveyor, filter cake (horizontal)	1	Belt, 18 in. wide x 50 ft long, 3 hp, 40 tons/hr, 100 ft/min	9,800	3,900
6.	Conveyor, filter cake (incline)	1	Belt, 18 in. wide x 100 ft long, 3 hp, 40 tons/hr, 100 ft/min	23,400	4,800
7.	Mobile equipment	1	Front-end loader, 23 yd^3/hr	80,000	-
	Subtotal			1,689,900	1,509,900

TABLE E-3. SAARBERG-HÖLTER PROCESS ENERGY REQUIREMENTS

Case	Reheat, kcal/hr	Electricity, kcal/hr (kW)	Process steam, kcal/hr	Oil, kcal/hr	Natural gas, kcal/hr	Total equivalent energy consumption,[a] % of input energy
500-MW unit						
Coal, 3.5% sulfur (base case)	17.70 M	22.00 M (9,701)	-	-	-	3.67
Coal, 0.8% sulfur	18.14 M	12.59 M (5,551)	-	-	-	2.89
Coal, 1.4% sulfur	17.53 M	13.76 M (6,065)	-	-	-	2.93
Coal, 2.0% sulfur	17.61 M	16.34 M (7,205)	-	-	-	3.17
Lignite, 0.5% sulfur	18.61 M	12.13 M (5,346)	-	-	-	2.89
Oil, 2.5% sulfur	14.74 M	13.78 M (6,078)	-	-	-	2.51

a. Based on a boiler efficiency of 90% for generation of steam and a gross heat rate of 9,000 Btu/kWh for generation of electricity.

TABLE E-4. SAARBERG-HÖLTER PROCESS CAPITAL INVESTMENT

Case	Total capital investment $	Total capital investment $/kW
500-MW unit		
Coal, 3.5% sulfur (base case)	44,024,000	88
Coal, 0.8% sulfur	35,481,000	71
Coal, 1.4% sulfur	36,472,000	73
Coal, 2.0% sulfur	39,173,000	78
Lignite, 0.5% sulfur	34,905,000	70
Oil, 2.5% sulfur	34,802,000	70

TABLE E-5. SAARBERG-HÖLTER PROCESS ANNUAL REVENUE REQUIREMENTS

Case	$	Mills/kWh	$/ton coal (bbl oil) burned	$/MBtu heat input	$/ton sulfur removed
500-MW unit					
Coal, 3.5% sulfur (base case)	13,706,300	4.57	10.66	0.51	402
Coal, 0.8% sulfur	9,825,900	3.28	6.96	0.36	1,231
Coal, 1.4% sulfur	10,303,700	3.43	9.62	0.38	870
Coal, 2.0% sulfur	11,443,300	3.81	9.32	0.42	609
Lignite, 0.5% sulfur	9,571,100	3.19	5.60	0.35	1,647
Oil, 2.5% sulfur	10,347,600	3.45	(2.32)	0.38	646

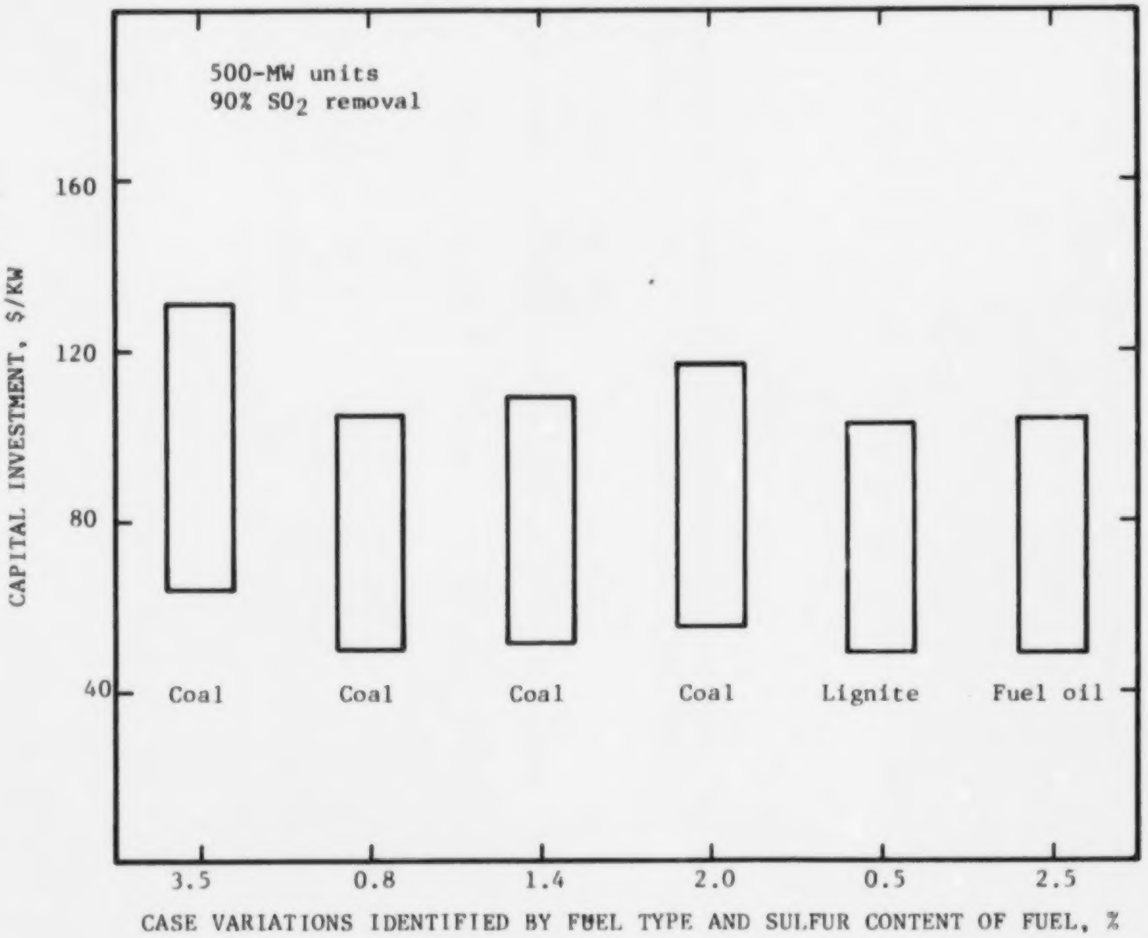

Figure E-2. Saarberg-Holter process capital investment range.

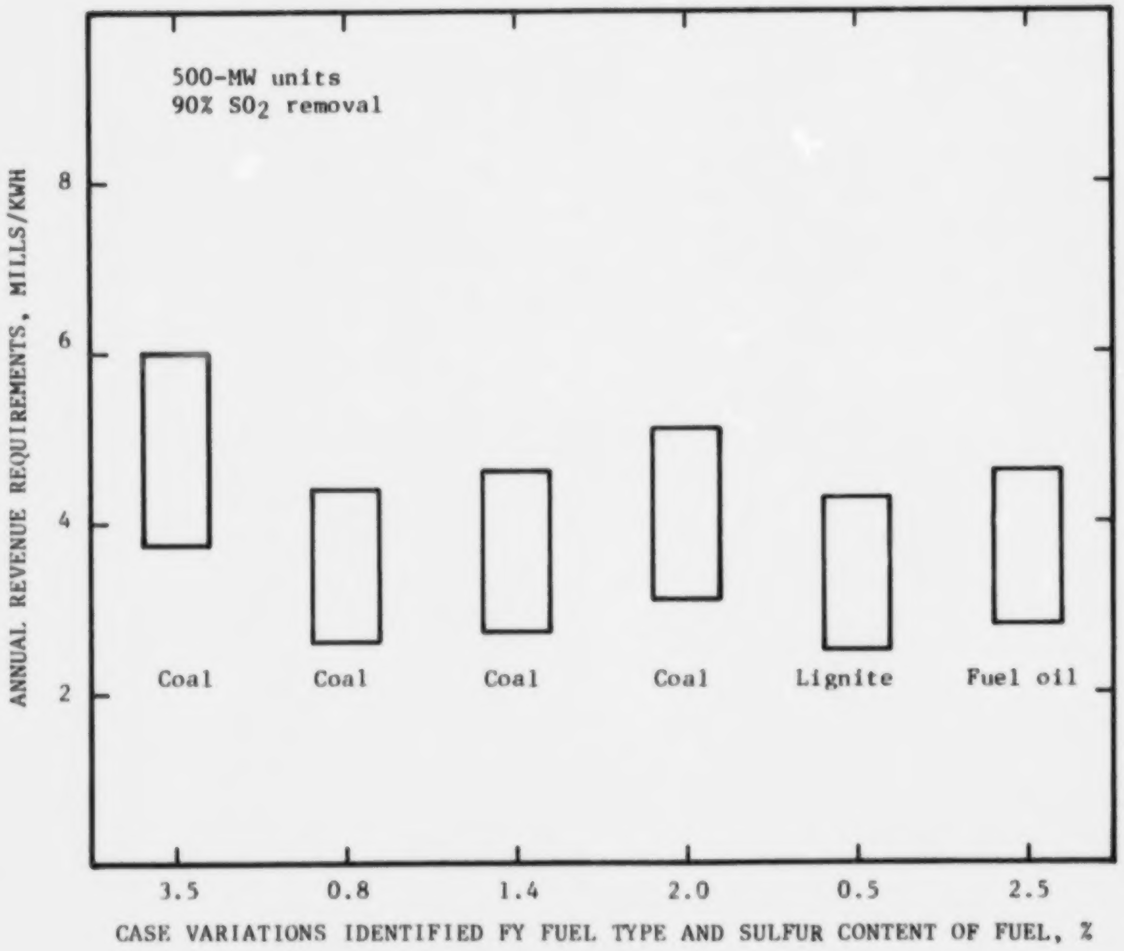

Figure E-3. Saarberg-Holter process annual revenue requirements range.

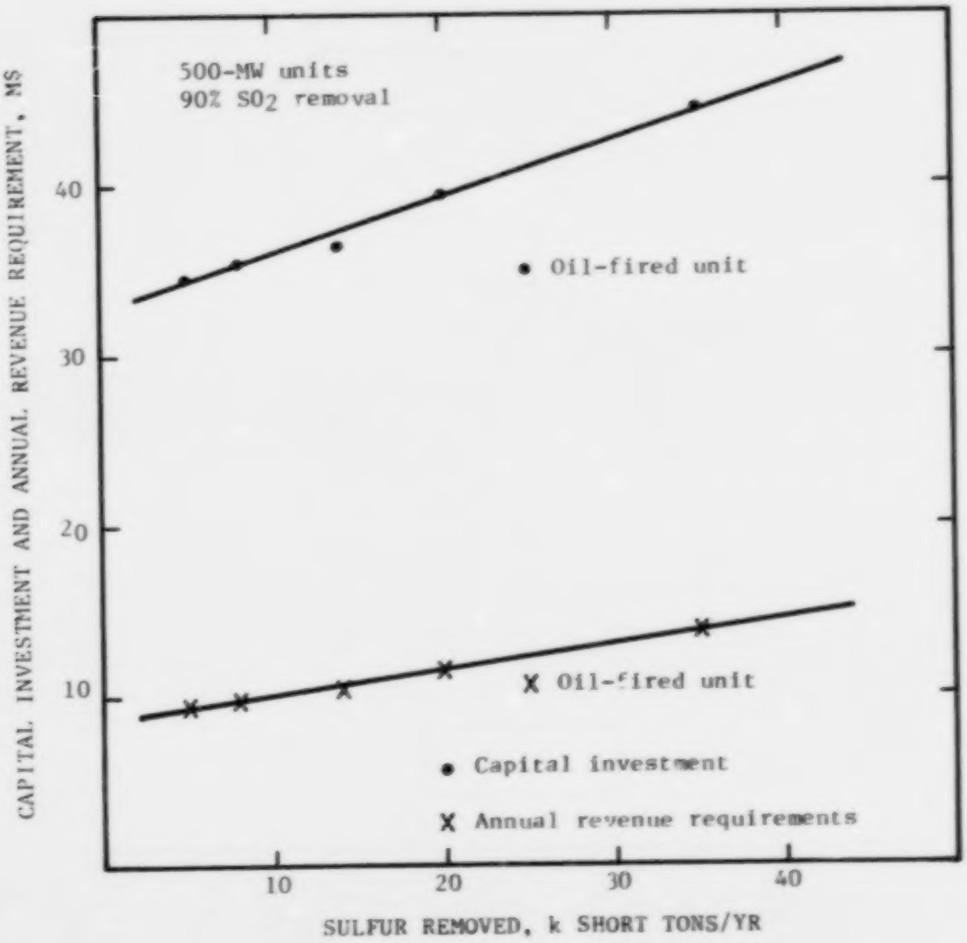

Figure E-4. Saarberg-Holter process. Effect of sulfur removed on capital investment and annual revenue requirements.

TABLE E-6. SAARBERG-HOLTER PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 3.5% sulfur in coal;
90% SO_2 removal; gypsum production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silo, and bin)	1,324,000	5.6
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	898,000	3.8
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,950,000	21.1
SO_2 absorption (four ROTOPART scrubber-separators, tank, and pumps)	7,518,000	32.0
Stack gas reheat (four indirect steam reheaters)	1,296,000	5.5
Oxidation (oxidation vessels, blowers, and pumps)	2,260,000	9.6
Solids disposal (thickeners, filters, conveyors, pumps, and front-end loader)	3,876,000	16.5
Subtotal	22,122,000	94.1
Services, utilities, and miscellaneous	1,327,000	5.7
Total process areas excluding gypsum field	23,449,000	99.8
Gypsum field construction	40,000	0.2
Total direct investment	23,489,000	100.0
Indirect Investment		
Engineering design and supervision	976,000	4.2
Architect and engineering contractor	243,000	1.0
Construction expense	3,438,000	14.6
Contractor fees	1,057,000	4.5
Total indirect investment	5,714,000	24.3
Contingency	5,841,000	24.9
Total fixed investment	35,044,000	149.2
Other Capital Charges		
Allowance for startup and modifications	3,500,000	14.9
Interest during construction	4,205,000	17.9
Total depreciable investment	42,749,000	182.0
Land	42,000	0.2
Working capital	1,233,000	5.2
Total capital investment	44,024,000	187.4

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE E-7. SAARBERG-HOLTER PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 3.5% sulfur
in coal; 90% SO_2 removal; gypsum production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Raw materials				
Lime	63,600 tons	40.00/ton	2,544,000	18.56
Formic acid	103,800 lb	0.25/lb	26,000	0.19
Flocculant	10,000 lb	1.00/lb	10,000	0.07
Nalco	1,000 lb	1.00/lb	1,000	0.01
Total raw materials cost			2,581,000	18.83
Conversion costs				
Operating labor and supervision	31,900 man-hr	12.50/man-hr	398,800	2.91
Utilities				
Steam	421,500 MBtu	2.00/MBtu	843,000	6.15
Process water	342,100 kgal	0.12/kgal	41,100	0.30
Electricity	58,208,700 kWh	0.029/kWh	1,688,100	12.32
Maintenance				
Labor and material			1,408,100	10.27
Analyses	3,220 man-hr	17.00/man-hr	54,700	0.40
Total conversion costs			4,433,800	32.35
Total direct costs			7,014,800	51.18
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,564,900	18.72
Average cost of capital and taxes at 8.6% of total capital investment			3,786,100	27.62
Overheads				
Plant, 50% of conversion costs less utilities			930,800	6.79
Administrative, 10% of operating labor			39,900	0.29
Marketing, 10% of byproduct sales revenue			70,000	0.51
Total indirect costs			7,391,700	53.93
Gross average annual revenue requirements			14,406,500	105.11
Byproduct Sales Revenue				
Byproduct gypsum	233,400 tons	3.00/ton	(700,200)	(5.11)
Net average annual revenue requirements			13,706,300	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements (net)	4.57	10.66	0.51	402

Basis
- 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 6,000 hr/yr.
- Coal burned, 1,166,221 metric tons/yr (1,285,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
- Stack gas reheat to 79°C (175°F).
- Sulfur removed, 30,947 metric tons/yr (34,120 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $23,489,000; total depreciable investment, $42,749,000; and total capital investment, $44,024,000.
- All tons shown are 2,000 lb.

TABLE E-8. SAARBERG-HOLTER PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 0.8% sulfur
in coal; 90% SO_2 removal; gypsum production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silo, and bin)	451,000	2.4
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	404,000	2.1
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	5,034,000	26.8
SO_2 absorption (four ROTOPART scrubber-separators, tank, and pumps)	7,691,000	41.0
Stack gas reheat (four indirect steam reheaters)	1,319,000	7.0
Oxidation (oxidation vessels, blowers, and pumps)	728,000	3.9
Solids disposal (thickeners, filters, conveyors, pumps, and front-end loader)	2,047,000	10.9
Subtotal	17,674,000	94.1
Services, utilities, and miscellaneous	1,060,000	5.7
Total process areas excluding gypsum field	18,734,000	99.8
Gypsum field construction	40,000	0.2
Total direct investment	18,774,000	100.0
Indirect Investment		
Engineering design and supervision	976,000	5.2
Architect and engineering contractor	243,000	1.3
Construction expense	2,853,000	15.2
Contractor fees	892,000	4.7
Total indirect investment	4,966,000	26.4
Contingency	4,748,000	25.3
Total fixed investment	28,488,000	151.7
Other Capital Charges		
Allowance for startup and modifications	2,845,000	15.2
Interest during construction	3,418,000	18.2
Total depreciable investment	34,751,000	185.1
Land	42,000	0.2
Working capital	688,000	3.7
Total capital investment	35,481,000	189.0

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE E-9. SAARBERG-HOLTER PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 0.8% sulfur in coal; 90% SO_2 removal; gypsum production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Raw materials				
Lime	14,900 tons	40.00/ton	596,000	6.07
Formic acid	24,300 lb	0.25/lb	6,100	0.06
Flocculant	2,340 lb	1.00/lb	2,300	0.02
Nalco	234 lb	1.00/lb	200	-
Total raw materials cost			604,600	6.15
Conversion costs				
Operating labor and supervision	31,900 man-hr	12.50/man-hr	398,800	4.06
Utilities				
Steam	431,900 MBtu	2.00/MBtu	863,800	8.79
Process water	350,500 kgal	0.12/kgal	42,100	0.43
Electricity	33,307,000 kWh	0.029/kWh	965,900	9.83
Maintenance				
Labor and material			1,125,200	11.45
Analyses	1,350 man-hr	17.00/man-hr	23,000	0.23
Total conversion costs			3,418,800	34.79
Total direct costs			4,023,400	40.94
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,085,100	21.22
Average cost of capital and taxes at 8.6% of total capital investment			3,051,400	31.05
Overheads				
Plant, 50% of conversion costs less utilities			773,500	7.86
Administrative, 10% of operating labor			39,900	0.41
Marketing, 10% of byproduct sales revenue			16,400	0.17
Total indirect costs			5,966,300	60.73
Gross average annual revenue requirements			9,989,700	101.67
Byproduct Sales Revenue				
Byproduct gypsum	54,600 tons	3.00/ton	(163,800)	(1.67)
Net average annual revenue requirements			9,825,900	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements (net)	3.28	6.96	0.36	1,231

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,288,934 metric tons/yr (1,412,100 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 7,240 metric tons/yr (7,980 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $18,774,000; total depreciable investment, $34,751,000; and total capital investment, $35,481,200.
All tons shown are 2,000 lb.

TABLE E-10. SAARBERG-HOLTER PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 1.4% sulfur in coal; 90% SO_2 removal; gypsum production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silo, and bin)	605,000	3.1
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	502,000	2.6
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,915,000	25.4
SO_2 absorption (four ROTOPART scrubber-separators, tank, and pumps)	7,450,000	38.6
Stack gas reheat (four indirect steam reheaters)	1,287,000	6.7
Oxidation (oxidation vessels, blowers, and pumps)	990,000	5.1
Solids disposal (thickeners, filters, conveyors, pumps, and front-end loader)	2,434,000	12.6
Subtotal	18,183,000	94.1
Services, utilities, and miscellaneous	1,091,000	5.7
Total process areas excluding gypsum field	19,274,000	99.8
Gypsum field construction	40,000	0.2
Total direct investment	19,314,000	100.0
Indirect Investment		
Engineering design and supervision	976,000	5.1
Architect and engineering contractor	243,000	1.3
Construction expense	2,923,000	15.1
Contractor fees	911,000	4.7
Total indirect investment	5,053,000	26.2
Contingency	4,873,000	25.2
Total fixed investment	29,240,000	151.4
Other Capital Charges		
Allowance for startup and modifications	2,920,000	15.1
Interest during construction	3,509,000	18.2
Total depreciable investment	35,669,000	184.7
Land	42,000	0.2
Working capital	761,000	3.9
Total capital investment	36,472,000	188.8

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE E-11. SAARBERG-HOLTER PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 1.4% sulfur in coal; 90% SO_2 removal; gypsum production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Raw materials				
Lime	2,100 tons	40.00/ton	884,000	8.58
Formic acid	36,000 lb	0.25/lb	9,000	0.09
Flocculant	3,470 lb	1.00/lb	3,500	0.03
Nalco	347 lb	1.00/lb	300	-
Total raw materials cost			896,800	8.70
Conversion costs				
Operating labor and supervision	31,900 man-hr	12.50/man-hr	398,800	3.87
Utilities				
Steam	417,400 MBtu	2.00/MBtu	834,800	8.10
Process water	338,700 kgal	0.12/kgal	40,600	0.39
Electricity	36,389,100 kWh	0.029/kWh	1,055,300	10.25
Maintenance				
Labor and material			1,157,600	11.23
Analyses	1,710 man-hr	17.00/man-hr	29,100	0.28
Total conversion costs			3,516,200	34.12
Total direct costs			4,413,000	42.82
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,140,100	20.77
Average cost of capital and taxes at 8.6% of total capital investment			3,136,600	30.45
Overheads				
Plant, 50% of conversion costs less utilities			792,800	7.69
Administrative, 10% of operating labor			39,900	0.39
Marketing, 10% of byproduct sales revenue			24,300	0.24
Total indirect costs			6,133,700	59.54
Gross average annual revenue requirements			10,546,700	102.36
Byproduct Sales Revenue				
Byproduct gypsum	81,000 tons	3.00/ton	(243,000)	(2.36)
Net average annual revenue requirements			10,303,700	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements (net)	3.43	9.62	0.38	870

Basis
- 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 6,000 hr/yr.
- Coal burned, 971,941 metric tons/yr (1,071,600 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
- Stack gas reheat to 79°C (175°F).
- Sulfur removed, 10,748 metric tons/yr (11,850 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $19,314,000; total depreciable investment, $35,669,000; and total capital investment, $36,472,000.
- All tons shown are 2,000 lb.

TABLE E-12. SAARBERG-HOLTER PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 2.0% sulfur in coal; 90% SO_2 removal; gypsum production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silo, and bin)	851,000	4.1
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	647,000	3.1
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,930,000	23.7
SO_2 absorption (four ROTOPART scrubber-separators, tank, and pumps)	7,480,000	35.9
Stack gas reheat (four indirect steam reheaters)	1,291,000	6.2
Oxidation (oxidation vessels, blowers, and pumps)	1,419,000	6.8
Solids disposal (thickeners, filters, conveyors, pumps, and front-end loader)	2,981,000	14.3
Subtotal	19,599,000	94.1
Services, utilities, and miscellaneous	1,176,000	5.7
Total process areas excluding gypsum field	20,775,000	99.8
Gypsum field construction	40,000	0.2
Total direct investment	20,815,000	100.0
Indirect Investment		
Engineering design and supervision	976,000	4.7
Architect and engineering contractor	243,000	1.2
Construction expense	3,110,000	14.9
Contractor fees	964,000	4.6
Total indirect investment	5,293,000	25.4
Contingency	5,222,000	25.1
Total fixed investment	31,330,000	150.5
Other Capital Charges		
Allowance for startup and modifications	3,129,000	15.0
Interest during construction	3,760,000	18.1
Total depreciable investment	38,219,000	183.6
Land	42,000	0.2
Working capital	912,000	4.4
Total capital investment	39,173,000	188.2

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE E-13. SAARBERG-HOLTER PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 2.0% sulfur in coal; 90% SO_2 removal; gypsum production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Raw materials				
Lime	35,000 tons	40.00/ton	1,400,000	12.23
Formic acid	57,200 lb	0.25/lb	14,300	0.12
Flocculant	5,510 lb	1.00/lb	5,500	0.05
Nalco	551 lb	1.00/lb	600	0.01
Total raw materials cost			1,420,400	12.41
Conversion costs				
Operating labor and supervision	31,900 man-hr	12.50/man-hr	398,800	3.49
Utilities				
Steam	419,300 MBtu	2.00/MBtu	838,600	7.33
Process water	340,300 kgal	0.12/kgal	40,800	0.36
Electricity	43,229,800 kWh	0.029/kWh	1,253,700	10.96
Maintenance				
Labor and material			1,247,700	10.90
Analyses	2,550 man-hr	17.00/man-hr	43,400	0.38
Total conversion costs			3,823,000	33.42
Total direct costs			5,243,400	45.83
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,293,100	20.04
Average cost of capital and taxes at 8.6% of total capital investment			3,368,800	29.43
Overheads				
Plant, 50% of conversion costs less utilities			845,000	7.38
Administrative, 10% of operating labor			39,900	0.35
Marketing, 10% of byproduct sales revenue			38,600	0.34
Total indirect costs			6,585,400	57.54
Gross average annual revenue requirements			11,828,800	103.37
Byproduct Sales Revenue				
Byproduct gypsum	128,500 tons	3.00/ton	(385,500)	(3.37)
Net average annual revenue requirements			11,443,300	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements (net)	3.81	9.32	0.42	609

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,113,161 metric tons/yr (1,227,300 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 17,043 metric tons/yr (18,790 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $20,815,000; total depreciable investment, $38,219,000; and total capital investment, $39,173,000.
All tons shown are 2,000 lb.

TABLE E-14. SAARBERG-HOLTER PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new lignite-fired power unit, 0.5% sulfur in lignite; 90% SO_2 removal; gypsum production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silo, and bin)	357,000	1.9
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	339,000	1.8
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorbers to reheater and stack)	5,118,000	27.7
SO_2 absorption (four ROTOPART scrubber-separators, tank, and pumps)	7,871,000	42.7
Stack gas reheat (four indirect steam reheaters)	1,345,000	7.3
Oxidation (oxidation vessels, blowers, and pumps)	567,000	3.1
Solids disposal (thickeners, filters, conveyors, pumps, and front-end loader)	1,779,000	9.6
Subtotal	17,376,000	94.1
Services, utilities, and miscellaneous	1,043,000	5.7
Total process areas excluding gypsum field	18,419,000	99.8
Gypsum field construction	40,000	0.2
Total direct investment	18,459,000	100.0
Indirect Investment		
Engineering design and supervision	976,000	5.3
Architect and engineering contractor	243,000	1.3
Construction expense	2,815,000	15.2
Contractor fees	880,000	4.8
Total indirect investment	4,914,000	26.6
Contingency	4,674,000	25.3
Total fixed investment	28,047,000	151.9
Other Capital Charges		
Allowance for startup and modifications	2,801,000	15.2
Interest during construction	3,366,000	18.3
Total depreciable investment	34,214,000	185.4
Land	42,000	0.2
Working capital	649,000	3.5
Total capital investment	34,905,000	189.1

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE E-15. SAARBERG-HOLTER PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new lignite-fired power unit, 0.5% sulfur in lignite; 90% SO_2 removal; gypsum production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Raw materials				
Lime	10,800 tons	40.00/ton	432,000	4.51
Formic acid	17,700 lb	0.25/lb	4,400	0.05
Flocculant	1,700 lb	1.00/lb	1,700	0.02
Nalco	170 lb	1.00/lb	200	-
Total raw materials cost			438,300	4.58
Conversion costs				
Operating labor and supervision	31,900 man-hr	12.50/man-hr	398,800	4.17
Utilities				
Steam	443,000 MBtu	2.00/MBtu	886,000	9.26
Process water	359,600 kgal	0.12/kgal	43,200	0.45
Electricity	32,075,300 kWh	0.029/kWh	930,200	9.72
Maintenance				
Labor and material			1,106,300	11.56
Analyses	1,11[illegible] man-hr	17.00/man-hr	18,900	0.20
Total conversion costs			3,383,400	35.46
Total direct costs			3,821,700	39.94
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,05[illegible],800	21.45
Average cost of capital and taxes at 8.6% of total capital investment			3,001,900	31.36
Overheads				
Plant, 50% of conversion costs less utilities			762,000	7.96
Administrative, 10% of operating labor			39,900	0.41
Marketing, 10% of byproduct sales revenue			11,900	0.12
Total indirect costs			5,868,500	61.30
Gross average annual revenue requirements			9,690,200	101.24
Byproduct Sales Revenue				
Byproduct gypsum	39,700 tons	3.00/ton	(119,100)	(1.24)
Net average annual revenue requirements			9,571,100	100.00

	Mills/kWh	$/ton lignite burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements (net)	3.19	5.60	0.35	1,647

Basis
- 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 6,000 hr/yr.
- Lignite burned, 1,549,900 metric tons/yr (1,708,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
- Stack gas reheat to 79°C (175°F).
- Sulfur removed, 5,270 metric tons/yr (5,810 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $18,459,000; total depreciable investment, $34,214,000; and total capital investment, $34,905,000.
- All tons shown are 2,000 lb.

TABLE E-16. SAARBERG-HOLTER PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new oil-fired power unit, 2.5% sulfur in oil; 90% SO_2 removal; gypsum production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeder, silo, and bin)	756,000	4.1
Feed preparation (feeders, slakers, tanks, agitators, and pumps)	593,000	3.2
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack)	4,371,000	23.9
SO_2 absorption (four ROTOPART scrubber-separators, tank, and pumps)	6,338,000	34.7
Stack gas reheat (four direct oil-fired reheaters)	1,130,000	6.2
Oxidation (oxidation vessels, blowers, and pumps)	1,252,000	6.8
Solids disposal (thickeners, filters, conveyors, pumps, and front-end loader)	2,779,000	15.2
Subtotal	17,219,000	94.1
Services, utilities, and miscellaneous	1,033,000	5.7
Total process areas excluding gypsum field	18,252,000	99.8
Gypsum field construction	40,000	0.2
Total direct investment	18,292,000	100.0
Indirect Investment		
Engineering design and supervision	976,000	5.3
Architect and engineering contractor	243,000	1.3
Construction expense	2,794,000	15.3
Contractor fees	874,000	4.8
Total indirect investment	4,887,000	26.7
Contingency	4,636,000	25.3
Total fixed investment	27,815,000	152.0
Other Capital Charges		
Allowance for startup and modifications	2,777,000	15.2
Interest during construction	3,338,000	18.3
Total depreciable investment	33,930,000	185.5
Land	42,000	0.2
Working capital	830,000	4.5
Total capital investment	34,802,000	190.2

Basis
Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE E-17. SAARBERG-HOLTER PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new oil-fired power unit, 2.5% sulfur in oil; 90% SO_2 removal; gypsum production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Raw materials				
Lime	29,900 tons	40.00/ton	1,196,000	11.56
Formic acid	48,700 lb	0.25/lb	12,200	0.12
Flocculant	4,700 lb	1.00/lb	4,700	0.05
Nalco	470 lb	1.00/lb	500	-
Total raw materials cost			1,213,400	11.73
Conversion costs				
Operating labor and supervision	31,900 man-hr	12.50/man-hr	398,800	3.85
Utilities				
Fuel oil (No. 6)	2,436,800 gal	0.40/gal	974,700	9.42
Process water	284,800 kgal	0.12/kgal	34,200	0.33
Electricity	36,465,100 kWh	0.029/kWh	1,057,500	10.22
Maintenance				
Labor and material			1,096,300	10.59
Analyses	2,050 man-hr	17.00/man-hr	34,900	0.34
Total conversion costs			3,596,400	34.75
Total direct costs			4,809,800	46.48
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,035,800	19.67
Average cost of capital and taxes at 8.6% of total capital investment			2,993,000	28.91
Overheads				
Plant, 50% of conversion costs less utilities			765,000	7.39
Administrative, 10% of operating labor			39,900	0.30
Marketing, 10% of byproduct sales revenue			32,900	0.32
Total indirect costs			5,866,600	56.70
Gross average annual revenue requirements			10,676,400	103.18
Byproduct Sales Revenue				
Byproduct gypsum	109,600 tons	3.00/to	(328,800)	(3.18)
Net average annual revenue requirements			10,347,600	100.00

	Mills/kWh	$/bbl oil burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements (net)	3.45	2.32	0.38	646

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Oil burned, 710 x 10^6 liters/yr (4,464,300 bbl/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 14,530 metric tons/yr (16,020 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $18,292,000; total depreciable investment, $33,930,000; and total capital investment, $34,802,000.
All tons shown are 2,000 lb.

APPENDIX F

JET-BUBBLING LIMESTONE PROCESS

CHIYODA THOROUGHBRED 121 PROCESS

PROCESS DESCRIPTION

The Chiyoda Thoroughbred 121 process, shown in Figure F-1, is a forced-oxidation limestone-scrubbing process which produces gypsum. It was developed from Chiyoda's dilute sulfuric acid process, the Thoroughbred 101.

Absorption, oxidation, and crystallization are accomplished in the same reactor vessel. The flue gas is cooled in a presaturator chamber and fed to the agitated jet-bubbling reactor. Air and a limestone slurry of 15% solids are introduced to the reactor where SO_2 is absorbed from the flue gas, oxidized to SO_4, and reacted with the limestone to form gypsum (calcium sulfate dihydrate). A bleedstream containing the gypsum crystals is pumped to a thickener. The thickener underflow containing 40% solids is filtered to approximately 80% solids. The filter cake is conveyed to a storage area and the filtrate is returned to the system for use in the wet ball mills. The material balance and equipment list are shown in Tables F-1 and F-2.

SPECIFIC PROCESS PREMISES

1. The reactor for absorption, oxidation, and neutralization is a Chiyoda jet-bubbling reactor equipped with a presaturator and mist eliminator. Pressure drop is 3.94k Pascals (15.8 inches H_2O). Complete oxidation of absorber SO_2 to gypsum is assumed.

2. A stoichiometry of 1.0 mole of $CaCO_3$ to 1.0 mole SO_2 removed and 1.0 mole of $CaCO_3$ to 2.0 mole of HCl removed is used.

ENERGY REQUIREMENTS

For base case conditions, reheat of the cleaned gas from 53°C to 79°C requires 43.5×10^3 kg/hr (95,900 lb/hr) of 243°C (470°F) steam at 3.55×10^3 kPa absolute pressure (500 psig) equivalent to about 18.16×10^6 kcal/hr.

The electrical power demand for the Chiyoda Thoroughbred 121 process, base case, is estimated to be about 8,090 kW or 1.6% of the rated production of a 500-MW power plant. For 6,000 hours of operation, the annual electrical energy consumption is 48.5×10^6 kWh.

The total equivalent energy consumption for the base case is approximately 38.53 x 10^6 kcal/hr or 3.4% of the input energy required for the 500-MW power unit. Summarized energy requirements for all cases are listed in Table F-3.

BYPRODUCT MANAGEMENT

ESP units remove 99.2% of the fly ash from the flue gas and, therefore, only a small amount of fly ash is found in the FGD process byproduct. (Fly ash emission from oil-fired units does not exceed the EPA particulate emission standard and fly ash collection facilities are not included in oil-fired power plant design.) Projected mass flow rates of byproduct for the base case are shown below.

Component	kg/hr	lb/hr
$CaSO_4 \cdot 2H_2O$	27,751	61,180
$CaCl_2$	456	1,005
Mg	27	60
Fly ash	149	329
Inerts	884	1,948
	29,267	64,522

The process is evaluated on the basis of 30-day storage of salable gypsum byproduct. A 0.4 hectare (one-acre) storage area has been provided for base case and all fuel variation estimates.

ECONOMIC EVALUATION

Capital investment and annual revenue requirements for the base case and five fuel variations are shown in Tables F-4 and F-5. The detailed results are shown in Tables F-6 through F-17. The estimated accuracy ranges of the economic analysis are shown in Figures F-2 and F-3. The effect of fuel content on costs is shown in Figure F-4.

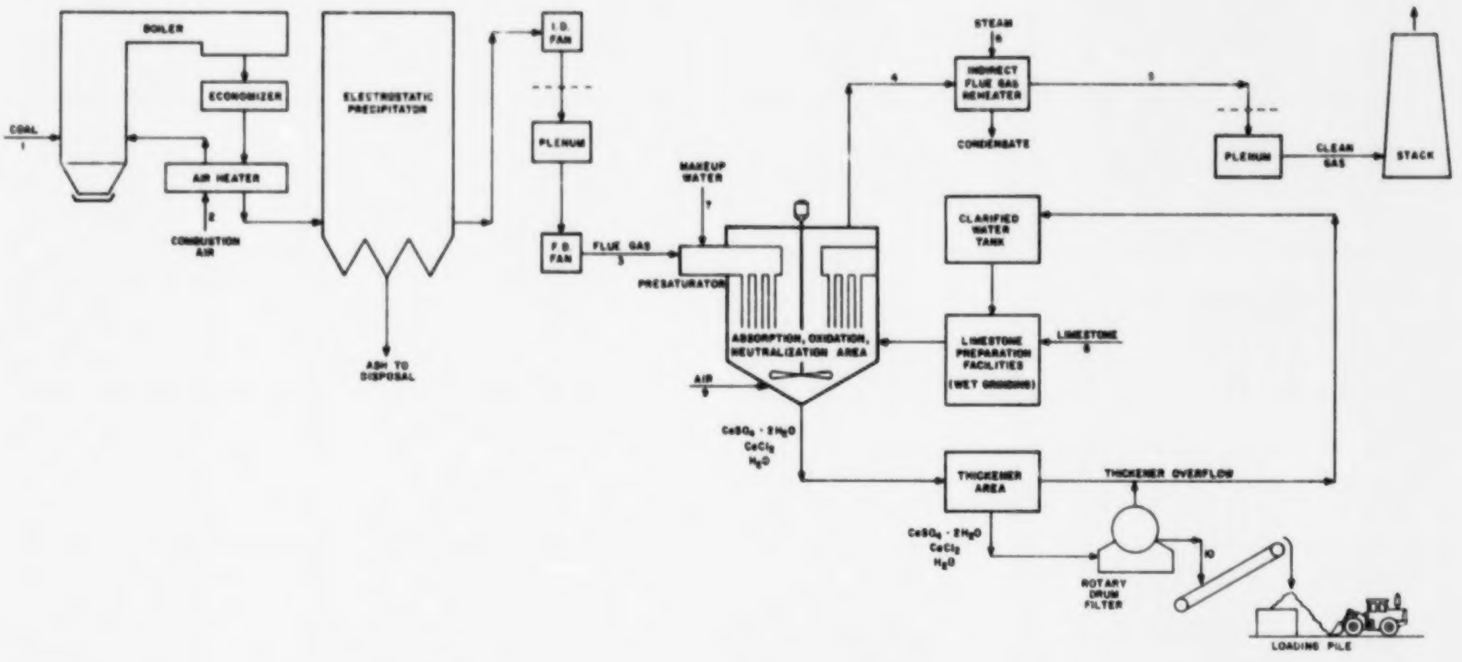
BOILER
COAL
1
ECONOMIZER
AIR HEATER
2
COMBUSTION AIR
ELECTROSTATIC PRECIPITATOR
ASH TO DISPOSAL
I.D. FAN
PLENUM
F.D. FAN
FLUE GAS
3
MAKEUP WATER
7
PRESATURATOR
ABSORPTION, OXIDATION, NEUTRALIZATION AREA
AIR
9
$CaSO_4 \cdot 2H_2O$
$CaCl_2$
H_2O
4
STEAM
6
INDIRECT FLUE GAS REHEATER
CONDENSATE
5
PLENUM
CLEAN GAS
STACK
CLARIFIED WATER TANK
LIMESTONE PREPARATION FACILITIES (WET GRINDING)
LIMESTONE
8
THICKENER AREA
THICKENER OVERFLOW
$CaSO_4 \cdot 2H_2O$
$CaCl_2$
H_2O
ROTARY DRUM FILTER
10
LOADING PILE

Figure F-1. Chiyoda Thoroughbred 121 process flow diagram.

TABLE F-1. CHIYODA THOROUGHBRED 121 PROCESS

MATERIAL BALANCE - BASE CASE (3.5% S COAL)

Stream No.		1	2	3	4	5
Description		Coal to boiler	Combustion air to air heater	Gas to absorber-reactor	Gas to reheater	Gas to stack
1	Total stream, 1000 kg/hr	194	2,062	2,225	2,387	2,387
2	Total stream, lb/hr	428,600	4,546,200	4,906,000	5,262,600	5,262,600
3	Gas flow, Nm^3/hr (0°C)		1,615,700	1,697,700	1,867,800	1,870,700
4	Gas flow, sft^3/min(60°F)		1,005,000	1,056,000	1,161,900	1,163,700
5	Liquid flow, liters/min				39.7	
6	Liquid flow, gal/min				10.5	
7	Temperature, °C		27	149	53	79
8	Particulates, kg/hr			199.1	49.8	49.8
9	Particulates, lb/hr			439	110	110
10						

Stream No.		6	7	8	9	10
Description		Steam to reheater	Makeup water to absorber-reactor	Limestone to system	Air to absorber-reactor	Product gypsum
1	Total stream, 1000 kg/hr	44	120	18	68	36
2	Total stream, lb/hr	95,900	265,000	40,159	148,900	79,400
3	Gas flow, Nm^3/hr (0°C)				52,800	
4	Gas flow, sft^3/min(60°F)				32,900	
5	Liquid flow, liters/min		2,004			
6	Liquid flow, gal/min		530			
7	Temperature, °C	243				
8	Pressure, kPa (abs)	3,550 x 10^3				
9	Pressure, psig	500				
10	Bulk density, kg/m^3					1,360 (80% sol)

1						
2						
3						
4						
5						
6						
7						
8						
9						
10						

1						
2						
3						
4						
5						
6						
7						
8						
9						
10						

TABLE F-2. CHIYODA THOROUGHBRED 121 PROCESS

BASE CASE EQUIPMENT LIST
DESCRIPTION AND COST

Area 1--Materials Handling			Area size-cost exponent 0.73	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Car shaker	1	Top mounting with crane	9,000	2,100
2. Car puller	1	25 hp puller, 5 hp return	50,000	2,100
3. Hopper, limestone unloading	1	12 ft x 20 ft x 2 ft bottom, 20 ft deep, 4,800 ft^3, carbon steel	9,300	8,700
4. Feeder, limestone unloading	1	Vibrating pan, 42 in. wide x 60 in. long, 3 hp, 250 ton/hr	4,800	1,100
5. Conveyor, limestone unloading	1	Belt, 36 in. wide x 10 ft long, 5 hp, 250 ton/hr, 130 ft/min	2,200	1,000
6. Conveyor, limestone stocking (incline)	1	Belt, 36 in. wide x 320 ft long, 30 hp, 15° slope, 250 ton/hr, 130 ft/min	48,000	15,400
7. Conveyor, limestone stocking	1	Belt, 36 in. wide x 200 ft long, 7-1/2 hp, 250 ton/hr, 130 ft/min	30,000	10,100
8. Tripper	1	1 hp, 30 ft/min	14,800	2,800
9. Mobile equipment	1	Scraper tractor, 22-24 yd^3 capacity	181,000	-
10. Hopper, reclaim	2	7 ft x 7 ft, 4 ft deep, 60° slope, carbon steel	10,700	1,900
11. Feeder, live limestone storage	2	Vibrating pan, 24 in. wide x 40 in. long, 1 hp, 15 ton/hr	7,000	2,100

(continued)

TABLE F-2. (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
12. Pump, tunnel sump	2	Vertical, 60 gpm, 70 ft head, 5 hp, carbon steel, neoprene lined (1 operating, 1 spare)	6,800	1,600
13. Conveyor, live limestone feed	1	Belt, 30 in. wide x 100 ft long, 2 hp, 100 ton/hr, 60 ft/min	14,400	5,100
14. Conveyor, live limestone feed (incline)	1	Belt, 30 in. wide x 190 ft long, 5 hp, 35 ft lift, 100 ton/hr, 60 ft/min	26,600	9,900
15. Elevator, live limestone feed	1	Continuous, bucket, 12 in. x 8 in. x 11-3/4 in., 20 hp, 75 ft lift, 100 ton/hr, 160 ft/min	30,800	1,800
16. Bin, crusher feed	2	13 ft dia x 21 ft high, w/cover, 3/8 in. carbon steel	10,900	15,700
17. Dust collecting system	1	Cyclone, 2,100 aft^3/min, motor-driven fan	5,900	4,800
18. Dust collecting system	1	Cyclone, 6,200 aft^3/min, motor-driven fan	14,200	11,100
19. Dust collecting system	1	Bag filter, polypropylene bag, 14,400 aft^3/min, automatic shaker system (1/2 cost in feed preparation area)	12,000	28,200
Subtotal			488,400	125,500

(continued)

TABLE F-2. (continued)

Area 2--Feed Preparation			Area size-cost exponent 0.70	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Discharge, feeder bin	2	Vibrating, 10 ton/hr, carbon steel	19,500	4,200
2. Feeder, crusher	2	Weigh belt, 18 in. wide x 14 ft long, 1-1/2 hp, 10 ton/hr	15,800	2,000
3. Crusher	2	Gyratory, 0 x 1-1/2 to 3/4 in., 50 hp, 10 ton/hr	82,200	11,700
4. Ball mill	2	Wet, open system, 8 ft dia x 13 ft long, 350 hp, 300 ton/day	424,500	35,200
Ball charge			31,100	-
5. Hoist	1	Electric, 5 tons, 7-1/2 hp,	8,300	2,100
6. Tank, mills product	1	6-1/2 ft dia x 7 ft high, 1,740 gal, open top, four 6-1/2 in. baffles, agitator supports, carbon steel (20 min residence time)	900	1,800
Lining		1/4 in. neoprene lining	1,000	1,300
7. Agitator, mills product tank	1	2 turbines, 22 in. dia, 3 hp, neoprene coated	6,200	700
8. Pump, mills product tank	2	Centrifugal, 80 gpm, 60 ft head, 5 hp, carbon steel, neoprene lined (1 operating, 1 spare)	3,800	1,200

(continued)

TABLE F-2. (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
9. Dust collecting system	1	Cyclone, 8,200 aft^3/min, motor-driven fan	16,300	12,700
10. Dust collecting system	1	Bag filter, 14,400 aft^3/min, automatic shaker system (1/2 cost in materials handling area)	12,000	28,200
Subtotal			621,600	101,100

Area 3--Gas Handling

Area size-cost exponent 0.68

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Fans	4	Forced draft, 22 in. static head, 875 rpm, 2,000 hp, fluid drive, double width, double inlet	1,811,300	118,100
Subtotal			1,811,300	118,100

Area 4--SO_2 Absorption-Oxidation-Neutralization

Area size-cost exponent 0.90

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Reactor, jet bubbling	4	Proprietary		
Presaturator	4	Proprietary		
Agitator		Proprietary		
Mist eliminator	4	Proprietary		

(continued)

TABLE F-2. (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
2. Compressor, oxidation air	4	Proprietary		
3. Pump, jet bubbling reactor underflow		Proprietary		
4. Tank, clarified water	1	10-1/2 ft dia x 12 ft high, 7,800 gal, open top, carbon steel (10 min residence time)	2,300	4,400
Lining		1/4 in. neoprene lining	2,400	2,900
5. Pump, clarified water tank	2	Centrifugal, 690 gpm, 100 ft head, 40 hp, carbon steel, neoprene lined (1 operating, 1 spare)	10,800	3,700
6. Tank, slurry feed	1	34-1/2 ft dia x 35-1/2 ft high, 248,300 gal, open top, four 34-1/2 in. baffles, agitator supports, carbon steel (8 hr residence time)	25,400	47,600
Lining		1/4 in. neoprene lining	25,900	31,700
7. Agitator, slurry feed tank	1	138 in. dia, 60 hp, neoprene coated	54,700	4,100
8. Pump, slurry feed tank	2	Centrifugal, 465 gpm, 60 ft head, 20 hp, carbon steel, neoprene lined (1 operating, 1 spare)	8,600	3,000
9. Pump, makeup water	2	Centrifugal, 481 gpm, 200 ft head, 50 hp, carbon steel, neoprene lined (1 operating, 1 spare)	23,000	6,300

(continued)

TABLE F-2. (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
10. Soot blowers	40	Air, retractable	260,000	225,800
Subtotal				

Area 5--Reheat

Area size-cost exponent 0.75

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Reheater	4	Steam, tube type, 3,700 ft^2, one-half of tubes made of Inconel 625 and one-half made of Cor-Ten	856,000	39,200
2. Soot blowers	20	Air, retractable	130,000	112,900
Subtotal			986,000	152,100

Area 6--Solids Separation and Storage

Area size-cost exponent 0.56

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Thickener	1	Carbon steel tank, 70 ft dia x 8 ft high, 230,300 gal, concrete basin, 4 ft high	27,700	67,900
Lining		1/4 in. neoprene lining	8,700	10,600
Rake motor and mechanism		5 hp	256,500	85,500

(continued)

TABLE F-2. (continued)

Item		No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
2.	Pump, thickener underflow	2	Centrifugal, 530 gpm, 60 ft head, 20 hp, carbon steel, neoprene lined (1 operating, 1 spare)	8,600	3,000
3.	Pump, thickener underflow	2	Centrifugal, 240 gpm, 100 ft head, 20 hp, carbon steel, neoprene lined (1 operating, 1 spare)	8,600	3,000
4.	Filter, rotary drum	2	Including vacuum pumps, filtrate pumps, filtrate receiver	255,500	25,900
5.	Pump, filtrate	2	Centrifugal, 190 gpm, 60 ft head, 7-1/2 hp, carbon steel, neoprene lined	7,700	2,900
6.	Conveyor, filtercake	1	Belt, 18 in. wide x 50 ft long, 1/2 hp, 40 ton/hr, 100 ft/min	9,800	3,900
7.	Conveyor, incline	1	Belt, 18 in. wide x 100 ft long, 3 hp, 40 ton/hr, 100 ft/min	23,400	4,800
8.	Pump, stack sump	2	Centrifugal, 160 gpm, 100 ft head, 10 hp, carbon steel, neoprene lined (1 operating, 1 spare)	7,700	1,500
9.	Mobile equipment	1	Front-end loader, 23 yd^3/hr	80,000	-
	Subtotal			694,200	209,000

TABLE F-3. CHIYODA THOROUGHBRED 121 PROCESS ENERGY REQUIREMENTS

Case	Reheat, kcal/hr	Electricity, kcal/hr (kW)	Process steam, kcal/hr	Oil, kcal/hr	Natural gas, kcal/hr	Total equivalent energy consumption,[a] % of input energy
500-MW unit						
Coal, 3.5% S (base case)	18.16 M	18.35 M (8,090)	-	-	-	3.40
Coal, 0.8% S	18.61 M	17.32 M (7,635)	-	-	-	3.35
Coal, 1.4% S	17.98 M	16.97 M (7,482)	-	-	-	3.26
Coal, 2.0% S	18.07 M	17.42 M (7,682)	-	-	-	3.31
Lignite, 0.5% S	19.09 M	17.63 M (7,773)	-	-	-	3.43
Oil, 2.5% S	15.12 M	14.64 M (6,453)	-	-	-	2.62

a. Based on a boiler efficiency of 90% for generation of steam and a gross heat rate of 9,000 Btu/kWh for generation of electricity.

TABLE F-4. CHIYODA THOROUGHBRED 121 PROCESS CAPITAL INVESTMENT

Case	Total capital investment $	Total capital investment $/kW
500-MW unit		
Coal, 3.5% S (base case)	47,017,000	94
Coal, 0.8% S	42,002,000	84
Coal, 1.4% S	42,007,000	84
Coal, 2.0% S	43,819,000	88
Lignite, 0.5% S	42,095,000	84
Oil, 2.5% S	38,532,000	77

TABLE F-5. CHIYODA THOROUGHBRED 121 PROCESS ANNUAL REVENUE REQUIREMENTS

Case	$	Mills/kWh	$/ton coal (bbl oil) burned	$/MBtu heat input	$/ton S removed
500-MW unit					
Coal, 3.5% S (base case)	12,160,100	4.05	9.46	0.45	356
Coal, 0.8% S	10,948,500	3.65	7.70	0.41	1,372
Coal, 1.4% S	10,919,500	3.64	10.19	0.40	921
Coal, 2.0% S	11,360,700	3.79	9.26	0.42	605
Lignite, 0.5% S	10,998,700	3.67	6.44	0.41	1,893
Oil, 2.5% S	10,219,200	3.41	2.29	0.38	638

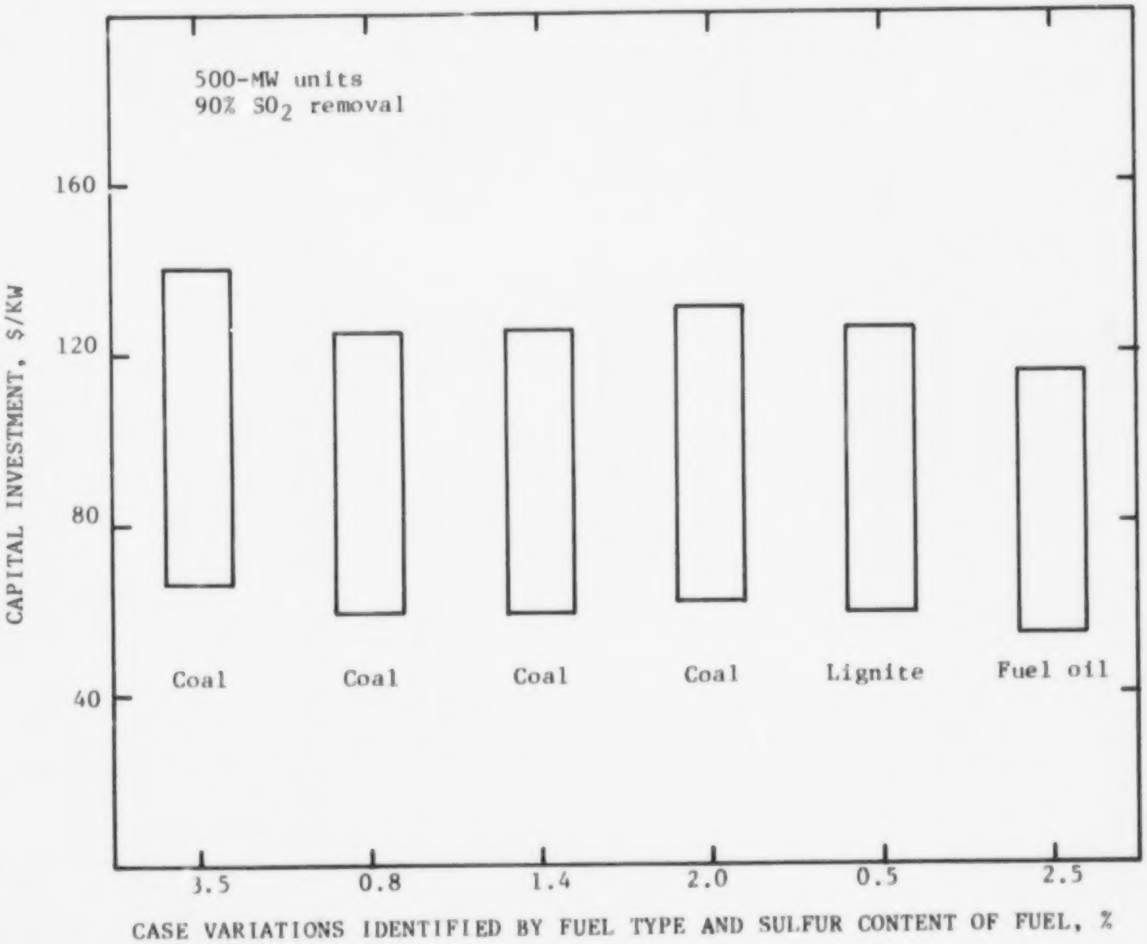

Figure F-2. Chiyoda 121 process capital investment range.

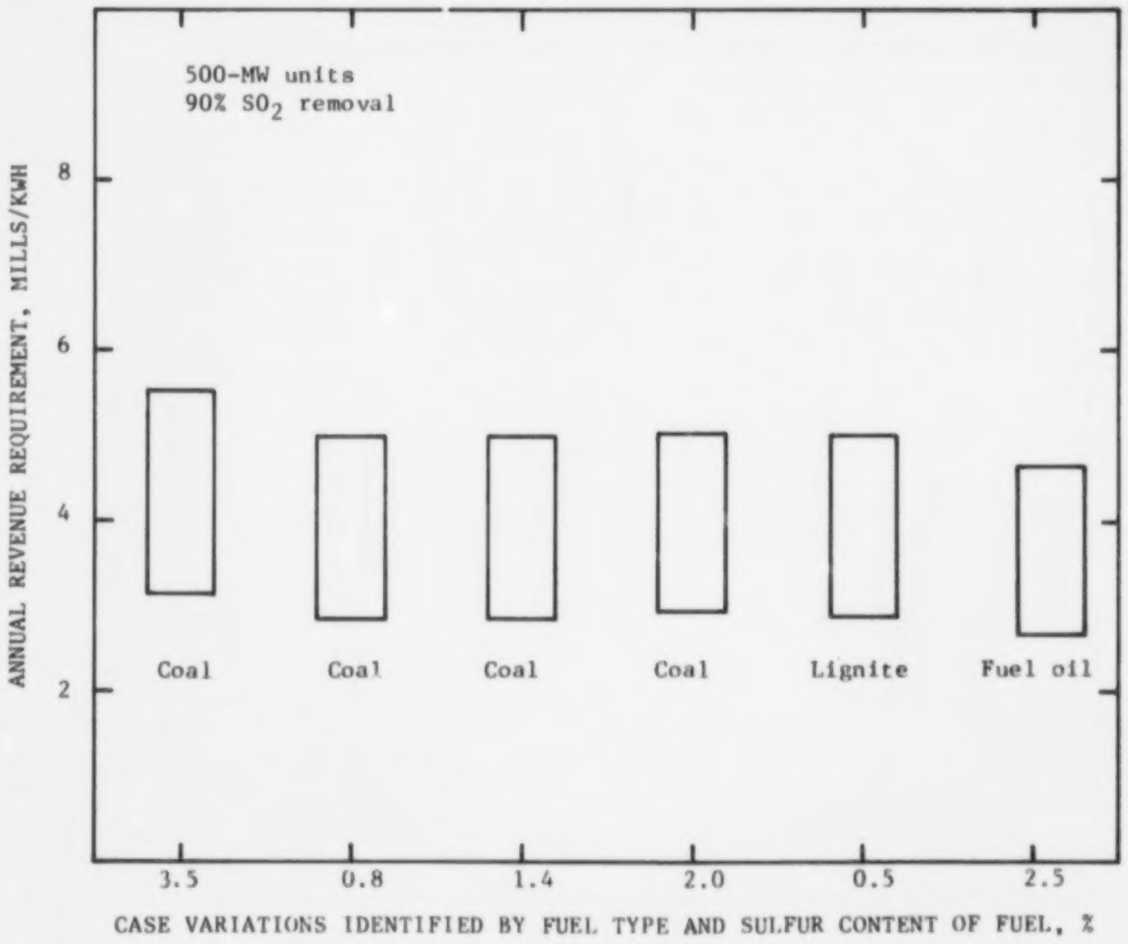

Figure F-3. Chiyoda 121 process annual revenue requirement range.

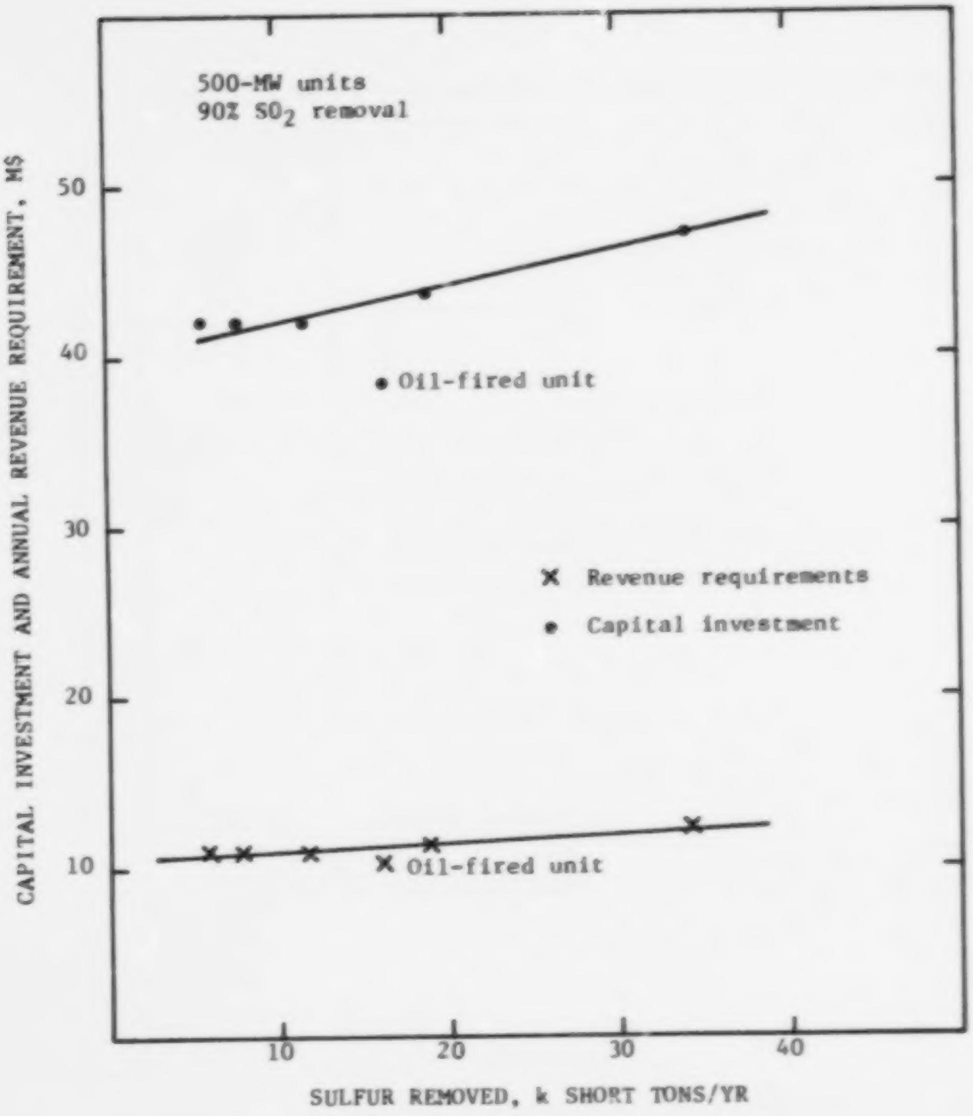

Figure F-4. Chiyoda 121 process. Effect of sulfur removed on capital investment and annual revenue requirement.

TABLE F-6. CHIYODA THOROUGHBRED 121 PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; gypsum production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	1,824,000	7.2
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	1,670,000	6.6
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to reactor, exhaust gas ducts and dampers from reactor to reheater and stack)	5,526,000	21.7
SO_2 absorption, oxidation, and neutralization (four jet bubbling reactors including presaturators and entrainment separators, compressors, tanks, and pumps)	12,166,000	47.8
Stack gas reheat (four indirect steam reheaters)	1,292,000	5.1
Solids separation and storage (thickener, filters, conveyors, pumps, and front-end loader)	1,486,000	5.8
Subtotal	23,964,000	94.2
Services, utilities, and miscellaneous	1,438,000	5.7
Total process areas excluding gypsum field	25,402,000	99.8
Gypsum field construction	40,000	0.2
Total direct investment	25,442,000	100.0
Indirect Investment		
Engineering design and supervision	1,011,000	4.0
Architect and engineering contractor	251,000	1.0
Construction expense	3,673,000	14.4
Contractor fees	1,123,000	4.4
Total indirect investment	6,058,000	23.8
Contingency	6,300,000	24.8
Total fixed investment	37,800,000	148.6
Allowance for startup and modification	3,776,000	14.8
Interest during construction	4,536,000	17.8
Total depreciable investment	46,112,000	181.2
Land	42,000	0.2
Working capital	863,000	3.4
Total capital investment	47,017,000	184.8

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[a] Basis
Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE F-7. CHIYODA THOROUGHBRED 121 PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; gypsum production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	115,200 tons	7.00/ton	806,400	6.63
Total raw materials cost			806,400	6.63
Conversion costs				
Operating labor and supervision	26,060 man-hr	12.50/man-hr	325,800	2.68
Utilities				
Steam	432,400 MBtu	2.00/MBtu	864,800	7.11
Process water	190,600 kgal	0.12/kgal	22,900	0.19
Electricity	48,539,000 kWh	0.029/kWh	1,407,600	11.58
Maintenance				
Labor and material			1,525,300	12.54
Analyses	3,220 man-hr	17.00/man-hr	54,700	0.45
Total conversion costs			4,201,100	34.55
Total direct costs			5,007,500	41.18
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,766,700	22.75
Average cost of capital and taxes at 8.6% of total capital investment			4,043,500	33.25
Overheads				
Plant, 50% of conversion costs less utilities			952,900	7.84
Administrative, 10% of operating labor			32,600	0.27
Marketing, 10% of byproduct sales revenue			71,500	0.59
Total indirect costs			7,867,200	64.70
Gross average annual revenue requirements			12,874,700	105.88
Byproduct Sales Revenue				
Byproduct gypsum	238,190 tons	3.00/ton	(714,600)	(5.88)
Net average annual revenue requirements			12,160,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	4.05	9.46	0.45	356

[a] Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,166,221 metric tons/yr (1,285,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 30,947 metric tons/yr (34,120 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $25,442,000; total depreciable investment, $46,112,000; and total capital investment, $47,017,000.
All tons shown are 2,000 lb.

TABLE F-8. CHIYODA THOROUGHBRED 121 PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit, 0.8% S in coal; 90% SO_2 removal; gypsum production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	631,000	2.8
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	605,000	2.7
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to reactor, exhaust gas ducts and dampers from reactor to reheater and stack)	5,620,000	24.9
SO_2 absorption, oxidation, and neutralization (four jet bubbling reactors including presaturators and entrainment separators, compressors, tanks, and pumps)	12,434,000	55.1
Stack gas reheat (four indirect steam reheaters)	1,315,000	5.8
Solids separation and storage (thickener, filters, conveyors, pumps, and front-end loader)	658,000	2.9
Subtotal	21,263,000	94.2
Services, utilities, and miscellaneous	1,276,000	5.6
Total process areas excluding gypsum field	22,539,000	99.8
Gypsum field construction	40,000	0.2
Total direct investment	22,579,000	100.0
Indirect Investment		
Engineering design and supervision	1,011,000	4.5
Architect and engineering contractor	251,000	1.1
Construction expense	3,327,000	14.7
Contractor fees	1,026,000	4.5
Total indirect investment	5,615,000	24.8
Contingency	5,639,000	25.0
Total fixed investment	33,833,000	149.8
Allowance for startup and modification	3,379,000	15.0
Interest during construction	4,060,000	18.0
Total depreciable investment	41,272,000	182.8
Land	42,000	0.2
Working capital	688,000	3.0
Total capital investment	42,002,000	186.0

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a. Basis
Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE F-9. CHIYODA THOROUGHBRED 121 PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit, 0.8% S in coal;
90% SO_2 removal; gypsum production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	26,900 tons	7.00/ton	188,300	1.72
Total raw materials cost			188,300	1.72
Conversion costs				
Operating labor and supervision	26,060 man-hr	12.50/man-hr	325,800	2.98
Utilities				
Steam	443,000 MBtu	2.00/MBtu	886,000	8.09
Process water	179,900 kgal	0.12/kgal	21,600	0.20
Electricity	45,810,100 kWh	0.029/kWh	1,328,500	12.13
Maintenance				
Labor and material			1,353,500	12.36
Analyses	1,350 man-hr	17.00/man-hr	23,000	0.21
Total conversion costs			3,938,400	35.97
Total direct costs			4,126,700	37.69
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,476,300	22.62
Average cost of capital and taxes at 8.6% of total capital investment			3,612,100	32.99
Overheads				
Plant, 50% of conversion costs less utilities			851,200	7.77
Administrative, 10% of operating labor			32,600	0.30
Marketing, 10% of byproduct sales revenue			16,700	0.15
Total indirect costs			6,988,900	63.83
Gross average annual revenue requirements			11,115,600	101.52
Byproduct Sales Revenue				
Byproduct gypsum	55,685 tons	3.00/ton	(167,100)	(1.52)
Net average annual revenue requirements			10,948,500	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	3.65	7.70	0.41	1,372

a. Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,288,938 metric tons/yr (1,421,100 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 7,238 metric tons/yr (7,980 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $22,579,000; total depreciable investment, $41,272,000; and total capital investment, $42,002,000.
All tons shown are 2,000 lb.

TABLE F-10. CHIYODA THOROUGHBRED 121 PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit, 1.4% S in coal;
90% SO_2 removal; gypsum production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	843,000	3.7
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	767,000	3.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to reactor, exhaust gas ducts and dampers from reactor to reheater and stack)	5,487,000	24.3
SO_2 absorption, oxidation, and neutralization (four jet bubbling reactors including presaturators and entrainment separators, compressors, tanks, and pumps)	12,057,000	53.4
Stack gas reheat (four indirect steam reheaters)	1,283,000	5.7
Solids separation and storage (thickener, filters, conveyors, pumps, and front-end loader)	822,000	3.6
Subtotal	21,259,000	94.2
Services, utilities, and miscellaneous	1,276,000	5.6
Total process areas excluding gypsum field	22,535,000	99.8
Gypsum field construction	40,000	0.2
Total direct investment	22,575,000	100.0
Indirect Investment		
Engineering design and supervision	1,011,000	4.5
Architect and engineering contractor	251,000	1.1
Construction expense	3,326,000	14.7
Contractor fees	1,026,000	4.5
Total indirect investment	5,614,000	24.8
Contingency	5,638,000	25.0
Total fixed investment	33,827,000	149.8
Allowance for startup and modification	3,379,000	15.0
Interest during construction	4,059,000	18.0
Total depreciable investment	41,265,000	182.8
Land	42,000	0.2
Working capital	700,000	3.1
Total capital investment	42,007,000	186.1

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[a] Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE F-11. CHIYODA THOROUGHBRED 121 PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit, 1.4% S in coal;
90% SO_2 removal; gypsum production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	40,000 tons	7.00/ton	280,000	2.56
Total raw materials cost			280,000	2.56
Conversion costs				
Operating labor and supervision	26,060 man-hr	12.50/man-hr	325,800	2.98
Utilities				
Steam	428,200 MBtu	2.00/MBtu	856,400	7.84
Process water	176,200 kgal	0.12/kgal	21,100	0.19
Electricity	44,891,500 kWh	0.029/kWh	1,301,900	11.92
Maintenance				
Labor and material			1,353,300	12.40
Analyses	1,710 man-hr	17.00/man-hr	29,100	0.27
Total conversion costs			3,837,600	35.60
Total direct costs			4,167,600	38.16
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,475,900	22.67
Average cost of capital and taxes at 8.6% of total capital investment			3,612,600	33.09
Overheads				
Plant, 50% of conversion costs less utilities			854,100	7.82
Administrative, 10% of operating labor			32,600	0.30
Marketing, 10% of byproduct sales revenue			24,800	0.23
Total indirect costs			7,000,000	64.11
Gross average annual revenue requirements			11,167,600	102.27
Byproduct Sales Revenue				
Byproduct gypsum	82,700 tons	3.00/ton	(248,100)	(2.27)
Net average annual revenue requirements			10,919,500	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	3.64	10.19	0.40	921

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a. Basis
- 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 6,000 hr/yr.
- Coal burned, 971,941 metric tons/yr (1,071,600 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
- Stack gas reheat to 79°C (175°F).
- Sulfur removed, 10,748 metric tons/yr (11,850 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $22,575,000; total depreciable investment, $41,265,000; and total capital investment, $42,007,000.
- All tons shown are 2,000 lb.

TABLE F-12. CHIYODA THOROUGHBRED 121 PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new coal-fired power unit, 2.0% S in coal; 90% SO_2 removal; gypsum production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	1,180,000	5.0
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	1,101,000	4.7
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to reactor, exhaust gas ducts and dampers from reactor to reheater and stack)	5,504,000	23.3
SO_2 absorption, oxidation, and neutralization (four jet bubbling reactors including presaturators and entrainment separators, compressors, tanks, and pumps)	12,105,000	51.3
Stack gas reheat (four indirect steam reheaters)	1,287,000	5.4
Solids separation and storage (thickener, filters, conveyors, pumps, and front-end loader)	1,064,000	4.5
Subtotal	22,241,000	94.2
Services, utilities, and miscellaneous	1,334,000	5.6
Total process areas excluding gypsum field	23,575,000	99.8
Gypsum field construction	40,000	0.2
Total direct investment	23,615,000	100.0
Indirect Investment		
Engineering design and supervision	1,011,000	4.3
Architect and engineering contractor	251,000	1.1
Construction expense	3,453,000	14.6
Contractor fees	1,061,000	4.5
Total indirect investment	5,776,000	24.5
Contingency	5,878,000	24.9
Total fixed investment	35,269,000	149.4
Allowance for startup and modification	3,523,000	14.9
Interest during construction	4,232,000	17.9
Total depreciable investment	43,024,000	182.2
Land	42,000	0.2
Working capital	753,000	3.2
Total capital investment	43,819,000	185.6

a. Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE F-13. CHIYODA THOROUGHBRED 121 PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new coal-fired power unit, 2.0% S in coal;
90% SO_2 removal; gypsum production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	63,400 tons	7.00/ton	443,800	3.90
Total raw materials cost			443,800	3.90
Conversion costs				
Operating labor and supervision	26,060 man-hr	12.50/man-hr	325,800	2.87
Utilities				
Steam	430,200 MBtu	2.00/MBtu	860,400	7.57
Process water	180,900 kgal	0.12/kgal	21,700	0.19
Electricity	46,094,900 kWh	0.029/kWh	1,336,800	11.77
Maintenance				
Labor and material			1,415,700	12.46
Analyses	2,250 man-hr	17.00/man-hr	38,300	0.34
Total conversion costs			3,998,700	35.20
Total direct costs			4,442,500	39.10
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,581,400	22.72
Average cost of capital and taxes at 8.6% of total capital investment			3,768,400	33.17
Overheads				
Plant, 50% of conversion costs less utilities			889,900	7.83
Administrative, 10% of operating labor			32,600	0.29
Marketing, 10% of byproduct sales revenue			39,400	0.35
Total indirect costs			7,311,700	64.36
Gross average annual revenue requirements			11,754,200	103.46
Byproduct Sales Revenue				
Byproduct gypsum	131,170 tons	3.00/ton	(393,500)	(3.46)
Net average annual revenue requirements			11,360,700	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	3.79	9.26	0.42	605

a. Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,113,161 metric tons/yr (1,227,300 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 17,043 metric tons/yr (18,790 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $23,615,000; total depreciable investment, $43,024,000; and total capital investment, $43,819,000.
All tons shown are 2,000 lb.

TABLE F-14. CHIYODA THOROUGHBRED 121 PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new lignite-fired power unit, 0.5% S in lignite;
90% SO_2 removal; gypsum production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	502,000	2.2
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	484,000	2.1
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to reactor, exhaust gas ducts and dampers from reactor to reheater and stack)	5,714,000	25.2
SO_2 absorption, oxidation, and neutralization (four jet bubbling reactors including presaturators and entrainment separators, compressors, tanks, and pumps)	12,726,000	56.3
Stack gas reheat (four indirect steam reheaters)	1,341,000	5.9
Solids separation and storage (thickener, filters, conveyors, pumps, and front-end loader)	551,000	2.4
Subtotal	21,318,000	94.1
Services, utilities, and miscellaneous	1,279,000	5.7
Total process areas excluding gypsum field	22,597,000	99.8
Gypsum field construction	40,000	0.2
Total direct investment	22,637,000	100.0
Indirect Investment		
Engineering design and supervision	1,011,000	4.5
Architect and engineering contractor	251,000	1.1
Construction expense	3,334,000	14.7
Contractor fees	1,028,000	4.5
Total indirect investment	5,624,000	24.8
Contingency	5,652,000	25.0
Total fixed investment	33,913,000	149.8
Allowance for startup and modification	3,387,000	15.0
Interest during construction	4,070,000	18.0
Total depreciable investment	41,370,000	182.8
Land	42,000	0.2
Working capital	683,000	3.0
Total capital investment	42,095,000	186.0

[a] Basis
Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE F-15. CHIYODA THOROUGHBRED 121 PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new lignite-fired power unit, 0.5% S in lignite;
90% SO_2 removal; gypsum production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	19,600 tons	7.00/ton	137,200	1.25
Total raw materials cost			137,200	1.25
Conversion costs				
Operating labor and supervision	26,060 man-hr	12.50/man-hr	325,800	2.96
Utilities				
Steam	454,500 MBtu	2.00/MBtu	909,000	8.26
Process water	183,100 kgal	0.12/kgal	22,000	0.20
Electricity	46,635,800 kWh	0.029/kWh	1,352,400	12.30
Maintenance				
Labor and material			1,357,000	12.34
Analyses	1,110 man-hr	17.00/man-hr	18,900	0.17
Total conversion costs			3,985,100	36.23
Total direct costs			4,122,300	37.48
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,482,200	22.57
Average cost of capital and taxes at 8.6% of total capital investment			3,620,200	32.91
Overheads				
Plant, 50% of conversion costs less utilities			850,900	7.74
Administrative, 10% of operating labor			32,600	0.30
Marketing, 10% of byproduct sales revenue			12,200	0.11
Total indirect costs			6,998,100	63.63
Gross average annual revenue requirements			11,120,400	101.11
Byproduct Sales Revenue				
Byproduct gypsum	40,560 tons	3.00/ton	(121,700)	(1.11)
Net average annual revenue requirements			10,998,700	100.00

	Mills/kWh	$/ton lignite burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	3.67	6.44	0.41	1,893

a. Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Lignite burned, 1,549,882 metric tons/yr (1,708,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 5,270 metric tons/yr (5,810 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $22,637,000; total depreciable investment, $41,370,000; and total capital investment, $42,095,000.
All tons shown are 2,000 lb.

TABLE F-16. CHIYODA THOROUGHBRED 121 PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT[a]

(500-MW new oil-fired power unit, 2.5% S in oil;
90% SO_2 removal; gypsum production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (hoppers, feeders, conveyors, elevator, bins, shaker, and puller)	1,051,000	5.1
Feed preparation (feeders, crushers, ball mills, hoist, tanks, agitators, and pumps)	984,000	4.8
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to reactor, exhaust gas ducts and dampers from reactor to reheater and stack)	4,879,000	23.8
SO_2 absorption, oxidation, and neutralization (four jet bubbling reactors including presaturators and entrainment separators, compressors, tanks, and pumps)	10,317,000	50.3
Stack gas reheat (four direct oil-fired reheaters)	1,127,000	5.5
Solids separation and storage (thickener, filters, conveyors, pumps, and front-end loader)	973,000	4.7
Subtotal	19,331,000	94.2
Services, utilities, and miscellaneous	1,160,000	5.6
Total process areas excluding gypsum field	20,491,000	99.8
Gypsum field construction	40,000	0.2
Total direct investment	20,531,000	100.0
Indirect Investment		
Engineering design and supervision	1,011,000	4.9
Architect and engineering contractor	251,000	1.2
Construction expense	3,075,000	15.0
Contractor fees	954,000	4.6
Total indirect investment	5,291,000	25.7
Contingency	5,164,000	25.2
Total fixed investment	30,986,000	150.9
Allowance for startup and modification	3,095,000	15.1
Interest during construction	3,718,000	18.1
Total depreciable investment	37,799,000	184.1
Land	42,000	0.2
Working capital	691,000	3.4
Total capital investment	38,532,000	187.7

[a] Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by direct oil-fired reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE F-17. CHIYODA THOROUGHBRED 121 PROCESS

SUMMARY OF AVERAGE ANNUAL REVENUE REQUIREMENTS - REGULATED UTILITY ECONOMICS[a]

(500-MW new oil-fired power unit, 2.5% S in oil;
90% SO_2 removal; gypsum production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net average annual revenue requirements
Direct Costs				
Raw materials				
Limestone	54,100 tons	7.00/ton	378,700	3.71
Total raw materials cost			378,700	3.71
Conversion costs				
Operating labor and supervision	26,060 man-hr	12.50/man-hr	325,800	3.19
Utilities				
Fuel oil (No. 6)	2,500,000 gal	0.40/gal	1,000,000	9.78
Process water	151,700 kgal	0.12/kgal	18,200	0.18
Electricity	38,719,500 kWh	0.029/kWh	1,122,900	10.99
Maintenance				
Labor and material			1,230,700	12.04
Analyses	2,050 man-hr	17.00/man-hr	34,900	0.34
Total conversion costs			3,732,500	36.52
Total direct costs			4,111,200	40.23
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,267,900	22.19
Average cost of capital and taxes at 8.6% of total capital investment			3,313,800	32.43
Overheads				
Plant, 50% of conversion costs less utilities			795,700	7.78
Administrative, 10% of operating labor			32,600	0.32
Marketing, 10% of byproduct sales revenue			33,500	0.33
Total indirect costs			6,443,500	63.05
Gross average annual revenue requirements			10,554,700	103.28
Byproduct Sales Revenue				
Byproduct gypsum	111,830 tons	3.00/ton	(335,500)	(3.28)
Net average annual revenue requirements			10,219,200	100.00

	Mills/kWh	$/bbl oil burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	3.41	2.29	0.38	638

a. Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Oil burned, 710 x 10^6 liters/yr (4,464,300 bbl/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 14,530 metric tons/yr (16,020 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $20,531,000; total depreciable investment, $37,799,000; and total capital investment, $38,532,000.
All tons shown are 2,000 lb.

APPENDIX G

MAGNESIUM OXIDE PROCESS

PROCESS DESCRIPTION

The magnesium oxide process is an absorbent-regenerating process which produces sulfuric acid. The flue gas is scrubbed with an MgO slurry, producing $MgSO_3$ and $MgSO_4$, which are dried and calcined to regenerate SO_2 and MgO. The SO_2 is processed to sulfuric acid and the MgO is returned to the system. The process flow diagram is shown in Figure G-1. The base-case material balance and equipment list are shown in Tables G-1 and G-2. A spray grid absorber with a chloride scrubber and mist eliminator is used. Makeup and regenerated MgO are slurried into a bleedstream of liquor from the absorber and recycled to the absorber. Humidification losses are added as a fresh water upstream wash for the mist eliminator.

Effluent from the absorber, containing approximately 15% solids, is pumped to two parallel centrifuges to separate the solids from the liquor. The centrate is returned to the absorber system. The centrifuge cake is dried in an oil-fired rotary dryer. The dryer off-gas is cleaned in a cyclone and fabric dust collector. A portion of the gas is recycled to the dryer combustion chamber for temperature control and the remainder is routed to the absorbers.

The discharge from the dryer and filters is transferred to an oil-fired fluid-bed calciner which contains a single calcination bed operating at 871°C (1600°F). The calciner off-gas, containing SO_2, is partially cleaned in a cyclone, cooled to about 371°C (700°F) in a waste heat boiler, and fed to a fabric filter for final cleaning before entering the sulfuric acid unit. The MgO collected in the cyclone and bag filter is returned to the absorber feed preparation system.

A complete 390 metric ton/day contact sulfuric acid plant is provided for production of 98% acid from the SO_2 gas. The sulfuric acid is stored in 30-day-capacity tanks. Tail gas from the acid plant is recycled to the absorber.

SPECIFIC PROCESS PREMISES

1. The flue gas is assumed cooled from 149°C (300°F) to 53°C (127°F) and saturated in the presaturator chloride scrubber. The presaturator chloride scrubber L/G ratio is 0.5 liter/m^3 (4 gal/10^3 aft^3).

2. A mobile-bed absorber with a superficial velocity of 3.8 m/sec (12.5 ft/sec) and a pressure drop, including the mist eliminator, of 1.99 kPa (8 inches H_2O). The absorber L/G ratio is 3 liters/m^3 (20 gal/aft^3).

3. The stoichiometry is 1.05 moles of MgO to 1.0 mole of SO_2 removed.

ENERGY REQUIREMENTS

For base-case conditions, reheat of the cleaned gas from 53°C to 79°C requires 43.4 x 10^3 kg/hr (95,700 lb/hr) of 243°C (470°F) steam at 3.55 x 10^3 kPa absolute pressure (500 psig) equivalent to about 18.12 x 10^6 kcal/hr.

The electrical power demand for the base-case magnesium oxide process is about 9,109 kW or 1.8% of the rated output of a 500-MW power plant. For 6,000 hours of operation, the annual electrical energy consumption is 54.65 x 10^6 kWh.

Fuel oil provides energy for the dryer and calciner. The total fuel oil consumption of approximately 3,690 liters/hr (975 gal/hr) is equivalent to 33.78 x 10^6 kcal/hr.

Waste heat is recovered in the acid production area and in the calcining area to produce 5.76 x 10^3 kg/hr (12,700 lb/hr) of 186°C (367°F) steam at 1.14 x 10^3 kPa absolute pressure (150 psig). This steam is equivalent to 3.6 x 10^6 kcal/hr and is considered a heat credit in the determination of total equivalent energy consumption.

The total equivalent energy consumption for the base case is approximately 70.97 Mkcal/hr or 6.26% of the input energy required for the 500-MW power unit. Summarized energy requirements for all cases are listed in Table G-3.

BYPRODUCT MANAGEMENT

ESP units remove 99.2% of the fly ash from the flue gas and, therefore, only a small amount of fly ash is found in the chloride scrubber effluent. (Fly ash emission from oil-fired units does not exceed the EPA particulate emission standard and fly ash collection facilities are not included for these units.) Projected mass flow rates of the byproducts for the base case are shown below. HCl, SO_3, and ash are collected in the chloride scrubber and disposed of in the ash pond.

	Component	Kg/hr	Lb/hr
Product acid:	98% H_2SO_4	16,300	35,900
Chloride purge:	HCl	290	630
	SO_3	40	80
	Ash	150	330

The process is evaluated on the basis of 30-day storage of 98% sulfuric acid byproduct. Two 3,250 m^3 (858,000 gal) carbon steel tanks have been provided for the base-case design.

ECONOMIC EVALUATION

Capital investment and annual revenue requirement summaries for the magnesium oxide process are shown in Tables G-4 and G-5. Detailed results are shown in Tables G-6 through G-17. The results, showing the estimated ranges of accuracies, are also shown in Figures G-2 and G-3. The costs in terms of sulfur removed are shown in Figure G-4.

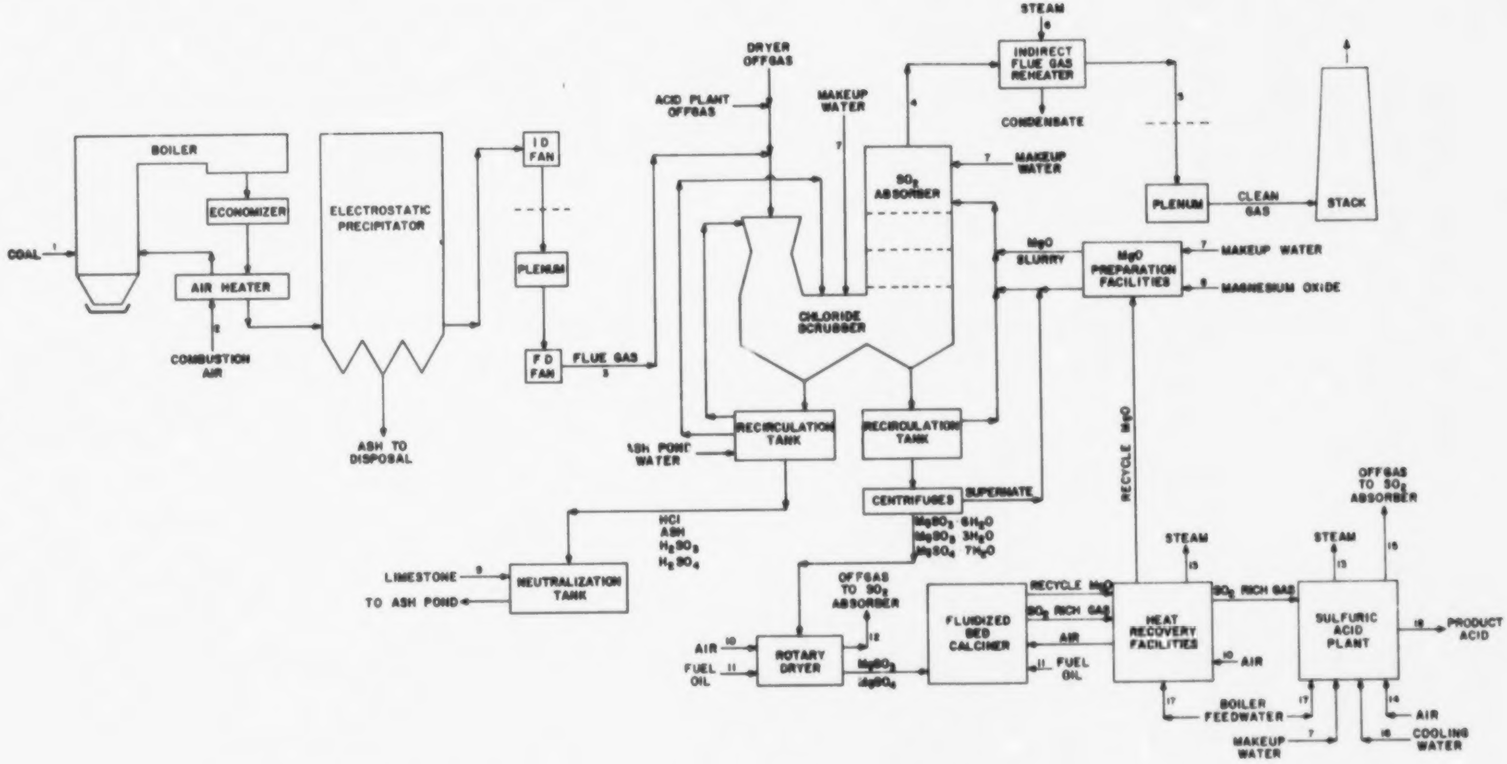
COAL
BOILER
ECONOMIZER
AIR HEATER
COMBUSTION AIR
ELECTROSTATIC PRECIPITATOR
ASH TO DISPOSAL
I D FAN
PLENUM
F D FAN
FLUE GAS
ACID PLANT OFFGAS
DRYER OFFGAS
MAKEUP WATER
CHLORIDE SCRUBBER
SO2 ABSORBER
RECIRCULATION TANK
RECIRCULATION TANK
ASH POND WATER
HCl
ASH
H2SO3
H2SO4
LIMESTONE
TO ASH POND
NEUTRALIZATION TANK
CENTRIFUGES
SUPERNATE
MgSO3 6H2O
MgSO3 3H2O
MgSO4 7H2O
STEAM
INDIRECT FLUE GAS REHEATER
CONDENSATE
PLENUM
CLEAN GAS
STACK
MgO SLURRY
MgO PREPARATION FACILITIES
MAKEUP WATER
MAGNESIUM OXIDE
RECYCLE MgO
OFFGAS TO SO2 ABSORBER
AIR
FUEL OIL
ROTARY DRYER
MgSO3
MgSO4
FLUIDIZED BED CALCINER
RECYCLE MgO
SO2 RICH GAS
AIR
FUEL OIL
HEAT RECOVERY FACILITIES
STEAM
AIR
BOILER FEEDWATER
SO2 RICH GAS
SULFURIC ACID PLANT
STEAM
OFFGAS TO SO2 ABSORBER
PRODUCT ACID
AIR
COOLING WATER
MAKEUP WATER

Figure G-1. Magnesium oxide process flow diagram.

TABLE G-1. MAGNESIUM OXIDE PROCESS

MATERIAL BALANCE - BASE CASE (3.5% SULFUR COAL)

	Stream No.	1	2	3	4	5
	Description	Coal to boiler	Combustion air to air heater	Flue gas to chloride scrubber	Gas to reheater	Gas to stack
1	Total stream, 1000 kg/hr	194	2,062	2,225	2,407	2,407
2	Total stream, lb/hr	428,600	4,546,200	4,906,000	5,306,000	5,306,000
3	Gas flow, Nm^3/hr (0°C)		1,615,700	1,697,700	1,883,900	1,886,800
4	Gas flow, sft^3/min (60°F)		1,005,000	1,056,000	1,171,900	1,173,800
5	Liquid flow, liters/min				40.1	
6	Liquid flow, gal/min				10.6	
7	Temperature, °C		27	149	53	79
8	Particulates, kg/hr			199.1	49.8	49.8
9	Particulates, lb/hr			439	110	110
10						

	Stream No.	6	7	8	9	10
	Description	Steam to reheater	Process makeup water	Magnesium oxide to preparation facilities	Limestone to neutralization tank	Combustion air to dryer and calciner
1	Total stream, 1000 kg/hr	43.4	110	.2	.4	62
2	Total stream, lb/hr	95,700	241,500	480	930	136,600
3	Gas flow, Nm^3/hr (0°C)					48,500
4	Gas flow, sft^3/min (60°F)					30,200
5	Liquid flow, liters/min		1,827			
6	Liquid flow, gal/min		483			
7	Temperature, °C	243				27
8	Pressure, Pascals (abs)	3.55 x 10^6				
9	Pressure, psig	500				
10	Specific gravity					

	Stream No.	11	12	13	14	15
	Description	Fuel oil to dryer and calciner	Dryer off-gas	Steam from heat recovery facilities	Oxidation air for sulfuric acid production	Acid plant off-gas
1	Total stream, 1000 kg/hr	3.2	66	5.8	35	47
2	Total stream, lb/hr	7,100	146,500	12,700	77,000	102,400
3	Gas flow, Nm^3/hr (0°C)		61,060		26,200	35,370
4	Gas flow, sft^3/min (60°F)		37,980		16,300	22,000
5	Liquid flow, liters/min	60				
6	Liquid flow, gal/min	16				
7	Temperature, °C		204	186	27	71
8	Pressure, Pascals (abs)			1.14 x 10^6		
9	Pressure, psig			150		
10	Specific gravity	0.91				

	Stream No.	16	17	18		
	Description	Cooling water to acid plant	Boiler feed water	Product sulfuric acid (98% H_2SO_4)		
1	Total stream, 1000 kg/hr	1,310	5.8	16.3		
2	Total stream, lb/hr	2,887,900	12,700	35,900		
3	Gas flow, Nm^3/hr (0°C)					
4	Gas flow, sft^3/min (60°F)					
5	Liquid flow, liters/min	21,950	95	150		
6	Liquid flow, gal/min	5,800	25	40		
7	Temperature, °C	27	38			
8	Pressure, Pascals (abs)					
9	Pressure, psig					
10	Specific gravity			1.82		

TABLE G-2. MAGNESIA SLURRY-REGENERATION PROCESS

BASE-CASE EQUIPMENT LIST
DESCRIPTION AND COST

Area 1--Materials Handling			Area size-cost exponent 0.64	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Conveyor, makeup MgO	1	Pneumatic, pressure, 100 hp	80,000	20,000
2. Silo, makeup MgO storage	1	28 ft dia x 41 ft straight side height, 25,250 ft^3, 60° slope, 3/8 in. carbon steel	30,300	69,000
3. Bin, makeup MgO feed	1	10 ft dia x 14 ft straight side height, w/cover, carbon steel	3,300	5,500
4. Feeder, makeup MgO	1	Vibrating screw, 8 in. dia x 4 ft long, 1 hp, 1,025 ft^3/hr, 8 tons/hr	5,500	500
5. Conveyor, recycle MgO feed	1	Pneumatic, pressure, 10 hp	43,000	20,000
6. Bin, recycle MgO feed	1	10 ft dia x 14 ft straight side height, w/cover, carbon steel	3,300	5,500
7. Feeder, recycle MgO	1	Vibrating screw, 8 in. dia x 4 ft long, 1 hp, 1,025 ft^3/hr, 8 tons/hr	5,500	500
8. Car shaker	1	Top mounting with crane	9,000	2,100
9. Conveyor, limestone	1	Pneumatic, pressure, 75 hp	51,800	12,200
10. Silo, limestone storage	1	19 ft dia x 29 ft straight side height, 8,200 ft^3, 60° slope, 3/8 in. carbon steel	13,000	33,000
11. Bin, limestone feed	1	5-1/2 ft dia x 8-1/2 straight side height, w/cover, carbon steel	1,500	2,200

(continued)

TABLE G-2 (continued)

	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
12.	Tank, fuel oil	1	46 ft dia x 48 ft high, 596,800 gal, w/cover, carbon steel	53,700	99,900
13.	Pump, fuel oil	2	Centrifugal, 11 gpm, 200 ft head, 2 hp, carbon steel (1 operating, 1 spare)	3,500	1,300
	Subtotal			303,400	271,700

Area 2--Feed Preparation

Area size-cost exponent 0.51

	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1.	Preslaker mixer	1	Blade, 14 in. dia x 8 ft long, 5 hp	6,200	1,000
2.	Tank, slurry feed	1	28 ft dia x 29 ft high, 133,600 gal, open top, four 28 in. baffles, agitator supports, carbon steel (8 hr residence time)	18,400	33,600
	Lining		1/4 in. neoprene lining	18,400	22,400
3.	Agitator, slurry feed tank	1	112 in. dia, 30 hp, neoprene coated	33,100	3,500
4.	Pump, MgO slurry feed tank	2	Centrifugal, 310 gpm, 150 ft head, 30 hp, carbon steel, neoprene coated (1 operating, 1 spare)	16,100	5,900
	Subtotal			92,200	66,400

(continued)

TABLE G-2 (continued)

Area 3--Gas Handling

Item	No.	Description	Area size-cost exponent 0.68 Total material cost, 1979 $	Total labor cost, 1979 $
1. Fans	4	Forced draft, 15 in., 890 rpm, 1,500 hp, fluid drive, double width, double inlet	1,573,500	95,500
Subtotal			1,573,500	95,500

Area 4--SO_2 Absorption

Item	No.	Description	Area size-cost exponent 0.79 Total material cost, 1979 $	Total labor cost, 1979 $
1. SO_2 absorber	4	Spray grid tower, 29 ft long x 15 ft wide x 38 ft high, 1/4 in. carbon steel, neoprene lining; FRP spray headers, 316 stainless steel chevron vane entrainment separator	3,274,100	200,000
2. Tank, SO_2 absorber recirculation	4	23 ft dia x 11-1/2 ft high, 35,700 gal, open top, four 23 in. baffles, agitator supports, carbon steel (10 min residence time)	27,100	49,200
Lining		1/4 in. neoprene lining	28,200	34,400
3. Agitator, SO_2 absorber recirculation tank	4	92 in. dia, 15 hp, neoprene coated	80,800	5,600
4. Pump, SO_2 absorber recycle	6	Centrifugal, 3,230 gpm, 100 ft head, 200 hp, carbon steel, neoprene lined (4 operating, 2 spare)	74,800	17,200

(continued)

TABLE G-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
5. Pump, makeup water	3	Centrifugal, 926 gpm, 150 ft head, 75 hp, carbon steel (2 operating, 1 spare)	50,400	13,200
6. Soot blowers	40	Air, retractable	260,000	225,800
Subtotal			3,795,400	545,400

Area 5--Reheat

Area size-cost exponent 0.75

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Reheater	4	Steam, tube type, 3,754 ft^2, one-half of tubes made of Inconel 625 and one-half made of Cor-Ten	858,000	41,200
2. Soot blowers	20	Air, retractable	130,000	112,900
Subtotal			988,000	154,100

Area 6--Chloride Removal

Area size-cost exponent 0.75

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Chloride scrubber	4	Venturi-spray chamber combination, Venturi: 13 ft dia x 25 ft overall height, variable throat, carbon steel, elastomer and tile lined, insulated	1,834,200	439,200

(continued)

TABLE G-2 (continued)

	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1.	(continued)		Spray chamber: 20 ft x 29 ft x 9 ft high, carbon steel, elastomer and tile lined, Hastelloy G nozzles with stellite tips; Hastelloy G mist eliminator		
2.	Tank, chloride recycle	4	14 ft dia x 11 ft high, 12,700 gal, open top, four 14 in. baffles, agitator supports, carbon steel (10 min residence time)	13,300	25,400
	Lining		1/4 in. neoprene lining	14,700	17,900
3.	Agitator, chloride recycle tank	4	56 in. dia, 5 hp, neoprene coated	36,100	3,400
4.	Pumps, venturi recirculation	6	Centrifugal, 3,140 gpm, 60 ft head, 100 hp, carbon steel, neoprene lined (4 operating, 2 spare)	88,700	23,900
5.	Pumps, spray chamber recirculation	6	Centrifugal, 3,140 gpm, 150 ft head, 250 hp, carbon steel, neoprene lined (4 operating, 2 spare)	159,400	28,300
6.	Feeder, limestone feed bin discharge	1	Weigh, screw, 6 in. dia x 10 ft long, 1 hp, 900 lb/hr	5,300	200
7.	Tank, chloride neutralization	1	13 ft dia x 11 ft high, 10,900 gal, open top, four 13 in. baffles, carbon steel (30 min residence time)	5,900	10,800
	Lining		1/4 in. neoprene lining	4,000	4,900
8.	Agitator, chloride neutralization tank	1	64 in. dia, 7-1/2 hp, neoprene coated	12,000	1,000

(continued)

TABLE G-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
9. Pump, chloride purge	2	Centrifugal, 362 gpm, 200 ft head, 40 hp, carbon steel, neoprene lined (1 operating, 1 spare)	21,100	6,200
10. Pump, pond water return	2	Centrifugal, 317 gpm, 150 ft head, 25 hp, carbon steel, neoprene lined (1 operating, 1 spare)	18,200	6,100
Subtotal			2,212,900	567,300

Area 7--Slurry Processing

Area size-cost exponent 0.68

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Centrifuge	2	40 in. dia x 140 in. long, solid bowl, stainless steel, 300 hp	654,000	70,000
2. Tank, centrate	1	15 ft dia x 7 ft high, 9,250 gal, open top, four 15 in. baffles, agitator supports, carbon steel (10 min residence time)	2,600	5,000
Lining		1/4 in. neoprene lined	2,900	3,500
3. Agitator, centrate tank	1	60 in. dia, 2 hp, neoprene coated	4,600	600
4. Pump, centrate	2	Centrifugal, 950 gpm, 150 ft head, 100 hp, carbon steel, neoprene lined (1 operating, 1 spare)	23,200	7,500
5. Conveyor, dryer feed	1	Screw, 16 in. dia, 15 ft long, 5 hp, 45 tons/hr, carbon steel	4,400	1,500
Subtotal			691,700	88,100

(continued)

TABLE G-2 (continued)

Area 8--Drying			Area size-cost exponent 0.53	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Dryer, $MgSO_3$	1	Rotary, 15 ft dia x 90 ft long, 200 hp, carbon steel	1,299,300	1,689,100
2. Fan, combustion air	1	Forced draft, 5 in. static head, 24,900 aft^3/min, 30 hp	18,500	3,700
3. Conveyor, dryer product	1	Screw, 16 in. dia, 15 ft long, 15 hp, 20 tons/hr, carbon steel	4,400	1,500
4. Conveyor, $MgSO_3$	1	Pneumatic, pressure, 100 hp	80,000	20,000
5. Bin, $MgSO_3$ storage hold	1	5 ft dia x 8 ft straight side height, w/cover, carbon steel	900	1,700
6. Feeder, $MgSO_3$ storage	1	Belt, 14 in. wide, 1 hp, 18 tons/hr	10,000	1,000
7. Conveyor, reserve $MgSO_3$ storage	1	Belt, 14 in. wide x 100 ft long, 2 hp, 18 tons/hr, 100 ft/min	17,300	5,500
8. Tripper	1	5 hp, 30 ft/min	18,000	3,000
9. Bucket tractor, mobile equipment	1	Scraper tractor, 1-1/2 yd^3 capacity	48,800	-
10. Hopper, $MgSO_3$ reserve storage	1	7 ft x 7 ft x 7 ft deep, 60° slope, carbon steel	400	800
11. Feeder, reserve $MgSO_3$	1	Rotary stargate, 2 hp, 50 tons/hr	7,900	300
12. Conveyor, reserve $MgSO_3$ feed	1	Pneumatic, pressure, 100 hp	80,000	20,000
13. Silo, $MgSO_3$ live storage	1	18 ft dia x 27 ft straight side height, 6,900 ft^3, 60° slope, 3/8 in. carbon steel	13,800	30,200
14. Feeder, calciner (enclosed)	1	Weigh belt, 18 in. wide, 1 hp, 18 tons/hr	8,500	900

(continued)

TABLE G-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
15. Conveyor, calciner feed	1	Belt, 18 in. wide x 10 ft long, 1 hp, 18 tons/hr, 100 ft/min	2,000	800
16. Dust collector	1	Cyclone, 92,300 aft^3/min	48,400	5,600
17. Dust collector	1	Bag filter, 92,300 aft^3/min	54,600	13,700
18. Fan, dryer off-gas	1	Induced draft, 23 in. static head, 92,300 aft^3/min, 500 hp	126,400	25,300
Subtotal			1,839,200	1,823,100

Area 9--Calcining

Area size-cost exponent 0.68

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Calciner	1	Fluid bed, 13 ft x 40 ft high, 12 in. fire brick, 10 in. insulating brick, carbon steel shell	474,000	393,200
2. Dust collector	1	Multiclone, 49,800 aft^3/min	64,400	7,000
3. Air preheater	1	Tube type, 10,650 ft^2, 316L stainless steel tubes, heads, and shell	143,900	143,900
4. Waste heat boiler	1	Tube type, 600 ft^2, 316L stainless steel tubes, heads, and shell	21,900	21,900
5. Cooler, solids	1	Tubed shell type, 5,650 ft^2, 6 ft dia x 50 ft long, 20 hp, twenty-seven 3 in. tubes	248,000	25,000
6. Bin, MgO cooler	1	6 ft dia x 7 ft straight side height, w/cover, carbon steel	1,000	1,800

(continued)

TABLE G-2 (continued)

	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
7.	Dust collector	1	Bag filter, 49,900 aft^3/min,	39,300	9,800
8.	Blower, combustion air	1	Single-stage centrifugal, 7,400 aft^3/min, 250 hp, 316 stainless steel	123,900	37,200
9.	Conveyor, recycle MgO	1	Pneumatic, pressure, 15 hp	31,300	8,000
10.	Silo, recycle MgO storage	1	43 ft dia x 65 ft straight side height, 94,400 ft^3, 60° slope, 3/8 in. carbon steel	69,200	160,700
	Vibrators	4	1/2 hp	5,400	1,200
	Subtotal			1,222,300	809,700

Area 10--98% Sulfuric Acid Production

Area size-cost exponent 0.70

	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1.	Complete H_2SO_4 unit	1	Complete 98% sulfuric acid unit, battery limits	6,576,000	-
	Subtotal			6,576,000	-

Area 11--Acid Storage and Shipping

Area size-cost exponent 0.68

	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1.	Tanks, sulfuric acid storage	2	53 ft dia x 52 ft high, 858,200 gal, w/cover, carbon steel, insulated (30 day capacity)	213,100	330,500

(continued)

TABLE G-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
2. Pump, tank discharge	2	Centrifugal, 400 gpm, 100 ft head, 40 hp, carbon steel (1 operating, 1 spare)	10,500	3,100
Subtotal			223,600	333,600

TABLE G-3. MAGNESIUM OXIDE PROCESS ENERGY REQUIREMENTS

Case	Reheat, kcal/hr	Electricity, kcal/hr (kW)	Process steam, kcal/hr	Oil, kcal/hr	Natural gas, kcal/hr	Heat credit, kcal/hr	Total equivalent energy consumption,[a] % of input energy
500-MW unit							
Coal, 3.5% S (base case)	18.12 M	20.66 M (9,109)	-	33.78 M	-	3.60 M	6.26
Coal, 0.8% S	18.57 M	16.38 M (7,223)	-	7.90 M	-	0.84 M	3.89
Coal, 1.4% S	17.95 M	16.57 M (7,307)	-	11.73 M	-	1.25 M	4.14
Coal, 2.0% S	18.03 M	17.87 M (7,878)	-	18.60 M	-	1.98 M	4.81
Lignite, 0.5% S	19.05 M	16.38 M (7,222)	-	5.75 M	-	0.61 M	3.76
Oil, 2.5% S	15.09 M	12.94 M (5,705)	-	15.86 M	-	1.69 M	3.72

a. Based on a boiler efficiency of 90% for generation of steam and a gross heat rate of 9,000 Btu/kWh for generation of electricity.

TABLE G-4. MAGNESIUM OXIDE PROCESS CAPITAL INVESTMENT

Case	Capital investment $	 $/kW
500-MW unit		
Coal, 3.5% S (base case)	68,434,000	137
Coal, 0.8% S	48,926,000	98
Coal, 1.4% S	52,043,000	104
Coal, 2.0% S	58,108,000	116
Lignite, 0.5% S	47,115,000	94
Oil, 2.5% S	44,591,000	89

TABLE G-5. MAGNESIUM OXIDE PROCESS ANNUAL REVENUE REQUIREMENTS

Case	Annual revenue requirements $	 Mills/kWh	 $/ton coal (bbl oil) burned	 $/MBtu heat input	 $/ton S removed
500-MW unit					
Coal, 3.5% S (base case)	17,546,000	5.85	13.65	0.65	514
Coal, 0.8% S	12,949,500	4.32	9.11	0.48	1,623
Coal, 1.4% S	13,651,200	4.55	12.74	0.51	1,152
Coal, 2.0% S	15,114,300	5.04	12.31	0.56	804
Lignite, 0.5% S	12,573,900	4.19	7.36	0.47	2,164
Oil, 2.5% S	11,984,600	3.99	(2.68)	0.44	748

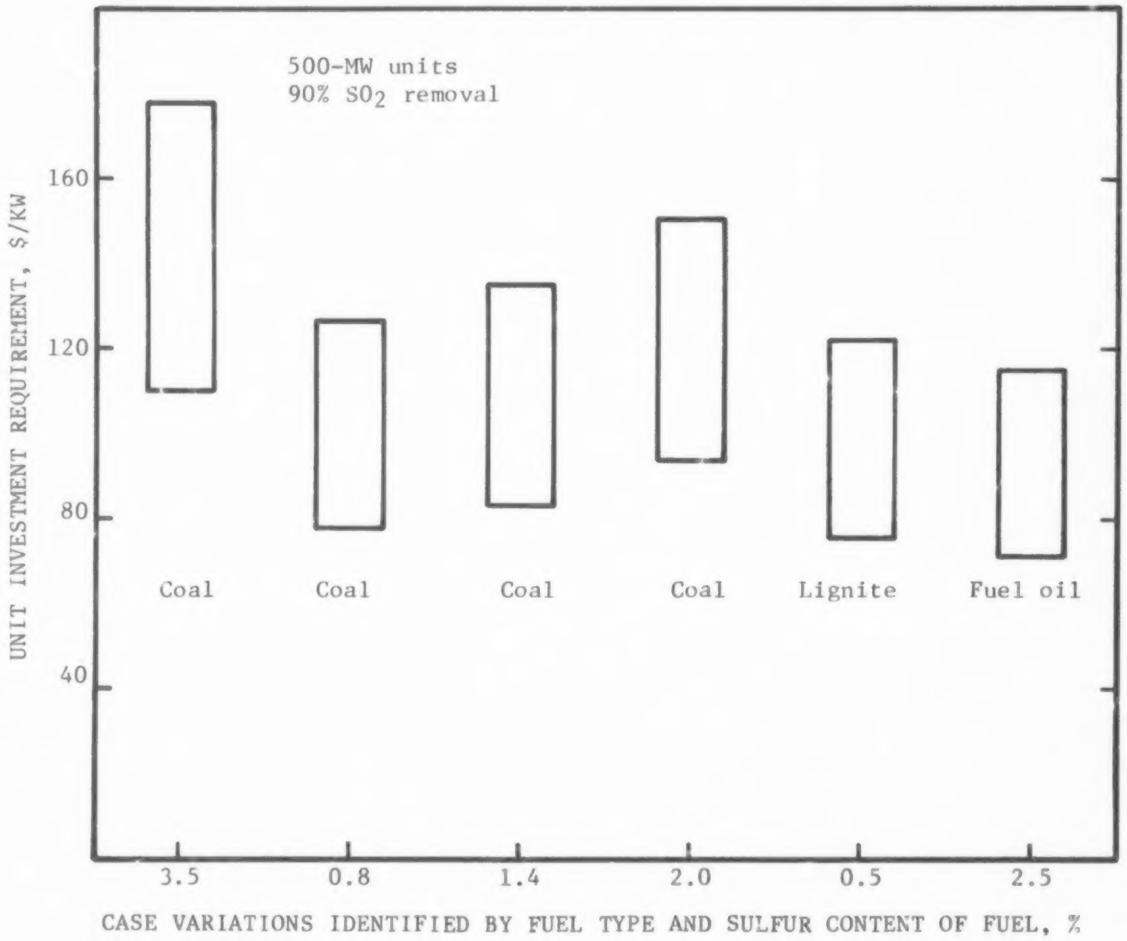

Figure G-2. Magnesium oxide process unit investment range.

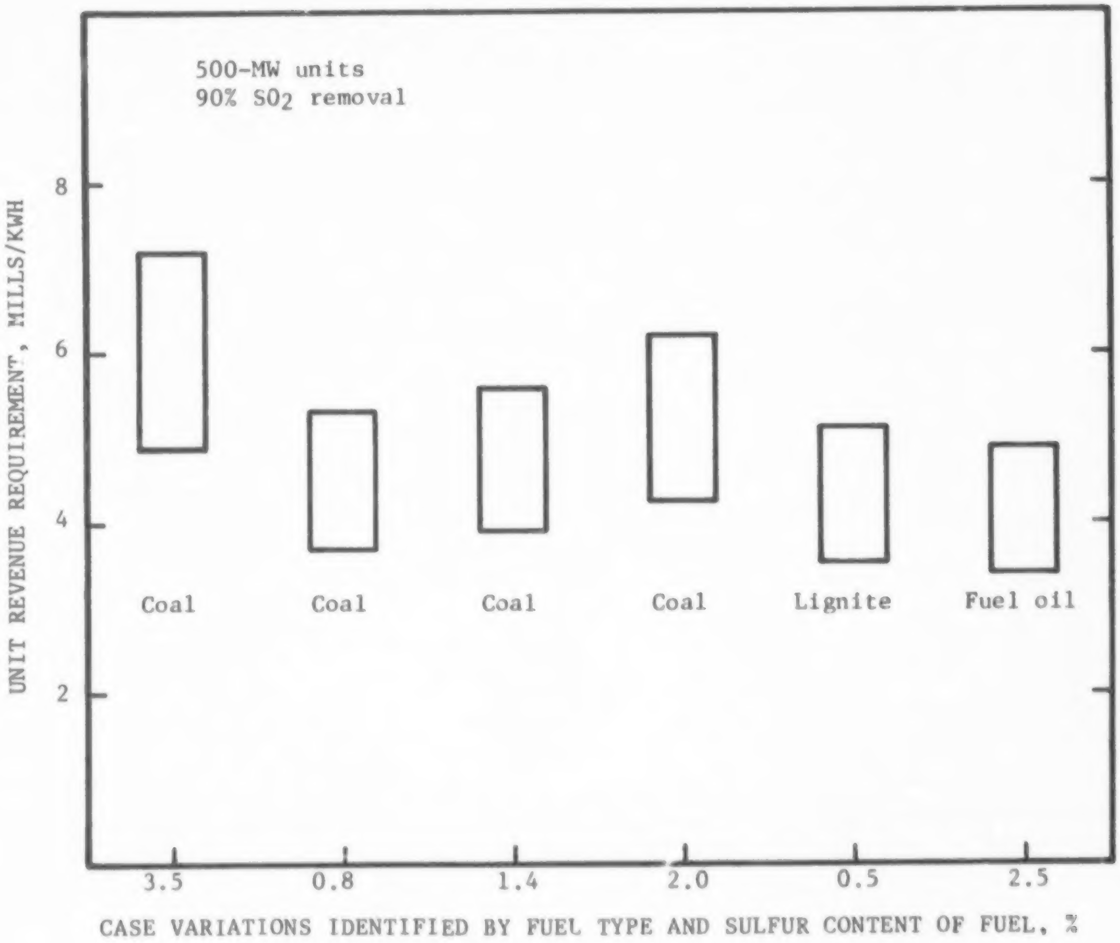

Figure G-3. Magnesium oxide process unit revenue requirement range.

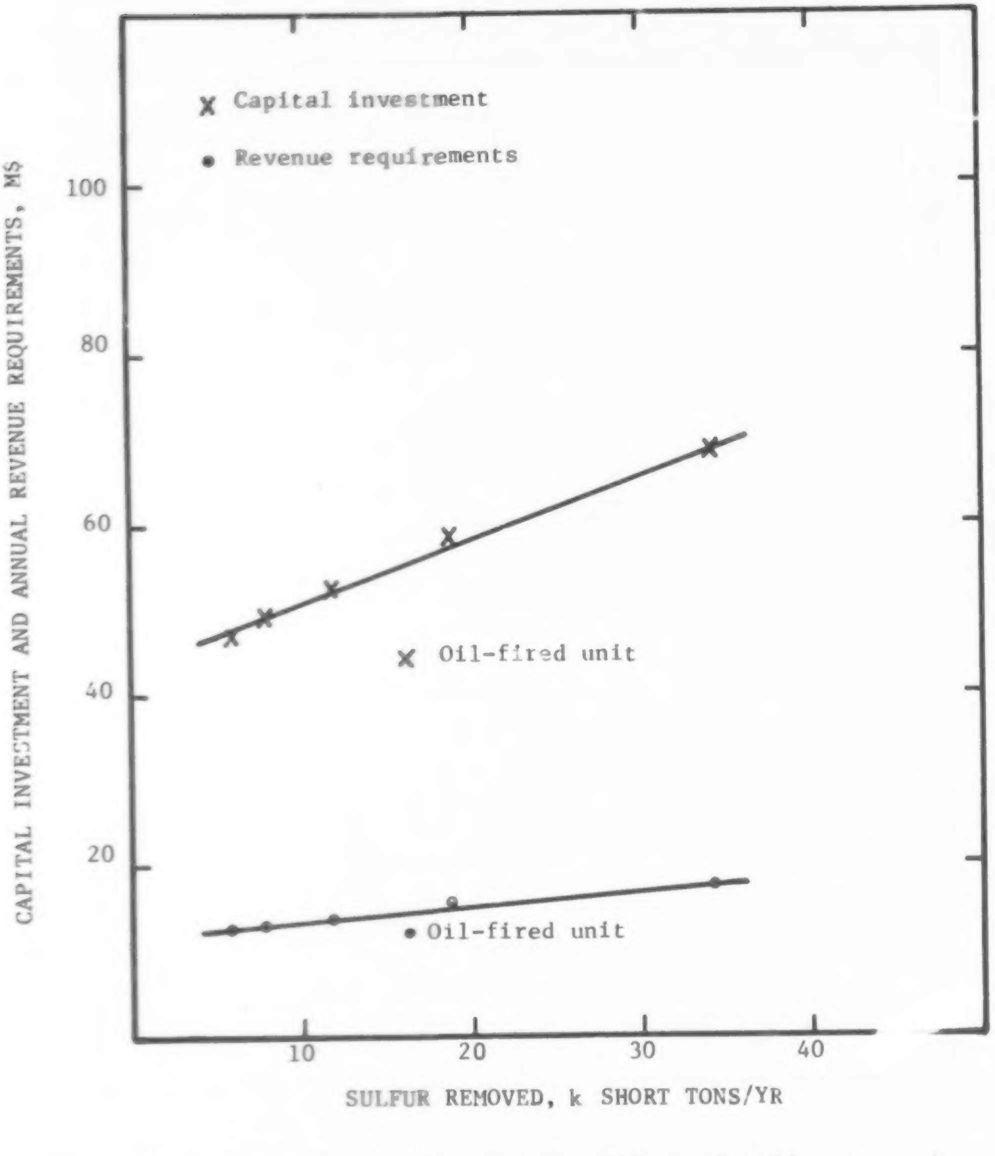

Figure G-4. Magnesium oxide process. Effect of sulfur removed on capital investment and annual revenue requirements.

TABLE G-6. MAGNESIUM OXIDE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; sulfuric acid production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, bins, and feeders)	765,000	2.1
Feed preparation (mixer, tank, agitator, and pumps)	326,000	0.9
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorbers to reheater and stack)	5,098,000	13.8
SO_2 absorption (four spray grid towers, including entrainment separators, tanks, agitators, and pumps)	5,447,000	14.8
Stack gas reheat (four indirect steam reheaters)	1,306,000	3.5
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	5,066,000	13.7
Slurry processing (centrifuge, conveyor, tank, agitator, and pumps)	1,211,000	3.3
Drying (dryer, conveyors, silos, fans, tanks, and pumps)	5,307,000	14.4
Calcining (calciner, cooler, bin, fans, conveyors, and silos)	2,461,000	6.7
Acid production (complete contact unit for sulfuric acid production)	6,576,000	17.9
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	1,077,000	2.9
Subtotal	34,640,000	94.0
Services, utilities, and miscellaneous	2,078,000	5.6
Total process areas excluding pond construction	36,718,000	99.6
Incremental ash pond cost	154,000	0.4
Total direct investment	36,872,000	100.0
Indirect Investment		
Engineering design and supervision	1,922,000	5.2
Architect and engineering contractor	477,000	1.3
Construction expense	5,002,000	13.6
Contractor fees	1,489,000	4.0
Total indirect investment	8,890,000	24.1
Contingency	9,153,000	24.8
Total fixed investment	54,915,000	148.9
Other Capital Charges		
Allowance for startup and modifications	5,476,000	14.9
Interest during construction	6,590,000	17.9
Total depreciable investment	66,981,000	181.7
Land	42,000	0.1
Working capital	1,411,000	3.8
Total capital investment	68,434,000	185.6

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE G-7. MAGNESIUM OXIDE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; sulfuric acid production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of annual revenue requirements
Direct Costs				
Delivered raw materials				
MgO	1,440 tons	300.00/ton	432,000	2.46
Catalyst	1,800 liters	2.50/liter	4,500	0.03
Agricultural limestone	2,780 tons	15.00/ton	41,700	0.24
Total raw materials cost			478,200	2.73
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	2.86
Utilities				
Fuel oil	5,585,100 gal	0.40/gal	2,234,000	12.73
Steam	431,500 MBtu	2.00/MBtu	863,000	4.92
Process water	2,251,400 kgal	0.12/kgal	270,200	1.54
Electricity	54,652,000 kWh	0.029/kWh	1,584,900	9.03
Heat credit	85,600 MBtu	2.00/MBtu	(171,200)	(0.98)
Maintenance				
Labor and material			2,574,900	14.67
Analyses	3,720 man-hr	17.00/man-hr	63,200	0.36
Total conversion costs			7,919,000	45.13
Total direct costs			8,397,200	47.86
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,018,900	22.90
Average cost of capital and taxes at 8.6% of total capital investment			5,885,400	33.54
Overheads				
Plant, 50% of conversion costs less utilities			1,569,100	8.95
Administrative, 10% of operating labor			50,000	0.28
Marketing, 10% of byproduct sales revenue			263,800	1.50
Total indirect costs			11,787,200	67.17
Gross annual revenue requirements			20,184,400	115.03
Byproduct Sales Revenue				
100% sulfuric acid	105,500 tons	25.00/ton	(2,637,500)	(15.03)
Net annual revenue requirements			17,546,900	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	5.85	13.65	0.65	514

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 6,000 hr/yr.
- Coal burned, 1,166,200 metric tons/yr (1,285,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
- Stack gas reheat to 79°C (175°F).
- Sulfur removed, 30,950 metric tons/yr (34,120 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $36,872,000; total depreciable investment, $66,981,000; and total capital investment, $68,434,000.
- All tons shown are 2,000 lb.

TABLE G-8. MAGNESIUM OXIDE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 0.8% S in coal;
90% SO_2 removal; sulfuric acid production;

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, bins, and feeders)	302,000	1.2
Feed preparation (mixer, tank, agitator, and pumps)	156,000	0.6
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorbers to reheater and stack)	5,185,000	20.0
SO_2 absorption (four spray grid towers, including entrainment separators, tanks, agitators, and pumps)	5,550,000	21.4
Stack gas reheat (four indirect steam reheaters)	1,330,000	5.1
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	5,157,000	19.9
Slurry processing (centrifuge, conveyor, tank, agitator, and pumps)	450,000	1.8
Drying (dryer, conveyors, silos, fans, tanks, and pumps)	2,457,000	9.5
Calcining (calciner, cooler, bin, fans, conveyors, and silos)	915,000	3.5
Acid production (complete contact unit for sulfuric acid production)	2,381,000	9.2
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	401,000	1.6
Subtotal	24,284,000	93.8
Services, utilities, and miscellaneous	1,457,000	5.6
Total process areas excluding pond construction	25,741,000	99.4
Incremental ash pond cost	156,000	0.6
Total direct investment	25,897,000	100.0
Indirect Investment		
Engineering design and supervision	1,628,000	6.3
Architect and engineering contractor	404,000	1.6
Construction expense	3,733,000	14.4
Contractor fees	1,138,000	4.4
Total indirect investment	6,903,000	26.7
Contingency	6,560,000	25.3
Total fixed investment	39,360,000	152.0
Other Capital Charges		
Allowance for startup and modifications	3,920,000	15.1
Interest during construction	4,723,000	18.2
Total depreciable investment	48,003,000	185.3
Land	42,000	0.2
Working capital	881,000	3.4
Total capital investment	48,926,000	188.9

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE G-9. MAGNESIUM OXIDE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 0.8% S in coal;
90% SO_2 removal; sulfuric acid production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of annual revenue requirements
Direct Costs				
Delivered raw materials				
MgO	340 tons	300.00/ton	102,000	0.79
Catalyst	420 liters	2.50/liter	1,100	-
Agricultural limestone	2,850 tons	15.00/ton	42,800	0.33
Total raw materials cost			145,900	1.12
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	3.86
Utilities				
Fuel oil	1,305,800 gal	0.40/gal	522,300	4.03
Steam	442,100 MBtu	2.00/MBtu	884,200	6.83
Process water	823,200 kgal	0.12/kgal	98,800	0.76
Electricity	43,336,000 kWh	0.029/kWh	1,256,700	9.71
Heat credit	20,000 MBtu	2.00/MBtu	(40,000)	(0.31)
Maintenance				
Labor and material			1,806,600	13.95
Analyses	1,555 man-hr	17.00/man-hr	26,400	0.21
Total conversion costs			5,055,600	39.04
Total direct costs			5,200,900	40.16
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,880,200	22.24
Average cost of capital and taxes at 8.6% of total capital investment			4,207,600	32.49
Overheads				
Plant, 50% of conversion costs less utilities			1,166,500	9.01
Administrative, 10% of operating labor			50,000	0.39
Marketing, 10% of byproduct sales revenue			61,800	0.48
Total indirect costs			8,366,100	64.61
Gross annual revenue requirements			13,567,000	104.77
Byproduct Sales Revenue				
100% sulfuric acid	24,700 tons	25.00/ton	(617,500)	(4.77)
Net annual revenue requirements			12,949,500	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	4.32	9.11	0.48	1,623

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 6,000 hr/yr.
- Coal burned, 1,289,200 metric tons/yr (1,421,100 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
- Stack gas reheat to 79°C (175°F).
- Sulfur removed, 7,240 metric tons/yr (7,980 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $25,897,000; total depreciable investment, $48,003,000; and total capital investment, $48,926,000.
- All tons shown are 2,000 lb.

TABLE G-10. MAGNESIUM OXIDE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 1.4% S in coal;
90% SO_2 removal; sulfuric acid production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, bins, and feeders)	389,000	1.4
Feed preparation (mixer, tank, agitator, and pumps)	190,000	0.7
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorbers to reheater and stack)	5,062,000	18.3
SO_2 absorption (four spray grid towers, including entrainment separators, tanks, agitators, and pumps)	5,403,000	19.6
Stack gas reheat (four indirect steam reheaters)	1,297,000	4.7
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	5,031,000	18.2
Slurry processing (centrifuge, conveyor, tank, agitator, and pumps)	590,000	2.1
Drying (dryer, conveyors, silos, fans, tanks, and pumps)	3,030,000	11.0
Calcining (calciner, cooler, bin, fans, conveyors, and silos)	1,199,000	4.3
Acid production (complete contact unit for sulfuric acid production)	3,137,000	11.4
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	524,000	1.9
Subtotal	25,852,000	93.6
Services, utilities, and miscellaneous	1,551,000	5.6
Total process areas excluding pond construction	27,403,000	99.2
Incremental ash pond cost	234,000	0.8
Total direct investment	27,637,000	100.0
Indirect Investment		
Engineering design and supervision	1,688,000	6.1
Architect and engineering contractor	418,000	1.5
Construction expense	3,941,000	14.3
Contractor fees	1,196,000	4.3
Total indirect investment	7,243,000	26.2
Contingency	6,976,000	25.2
Total fixed investment	41,856,000	151.4
Other Capital Charges		
Allowance for startup and modifications	4,162,000	15.1
Interest during construction	5,023,000	18.2
Total depreciable investment	51,041,000	184.7
Land	42,000	0.2
Working capital	960,000	3.5
Total capital investment	52,043,000	188.4

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE G-11. MAGNESIUM OXIDE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 1.4% S in coal;
90% SO_2 removal; sulfuric acid production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of annual revenue requirements
Direct Costs				
Delivered raw materials				
MgO	500 tons	300.00/ton	150,000	1.10
Catalyst	620 liters	2.50/liter	1,600	0.01
Agricultural limestone	5,500 tons	15.00/ton	82,500	0.60
Total raw materials cost			234,100	1.71
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	3.66
Utilities				
Fuel oil	1,939,100 gal	0.40/gal	775,600	5.68
Steam	427,300 MBtu	2.00/MBtu	854,600	6.26
Process water	1,023,000 kgal	0.12/kgal	122,800	0.90
Electricity	43,840,000 kWh	0.029/kWh	1,271,400	9.31
Heat credit	29,700 MBtu	2.00/MBtu	(59,400)	(0.44)
Maintenance				
Labor and material			1,925,200	14.10
Analyses	1,972 man-hr	17.00/man-hr	33,500	0.25
Total conversion costs			5,423,700	39.73
Total direct costs			5,657,800	41.44
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,062,500	22.43
Average cost of capital and taxes at 8.6% of total capital investment			4,475,700	32.79
Overheads				
Plant, 50% of conversion costs less utilities			1,229,400	9.00
Administrative, 10% of operating labor			50,000	0.37
Marketing, 10% of byproduct sales revenue			91,600	0.67
Total indirect costs			8,909,200	65.26
Gross annual revenue requirements			14,567,000	106.71
Byproduct Sales Revenue				
100% sulfuric acid	36,630 tons	25.00/ton	(915,800)	(6.71)
Net annual revenue requirements			13,651,200	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	4.55	12.74	0.51	1,152

Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 972,200 metric tons/yr (1,071,600 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 10,750 metric tons/yr (11,850 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $27,637,000; total depreciable investment, $51,041,000; and total capital investment, $52,043,000.
All tons shown are 2,000 lb.

TABLE G-12. MAGNESIUM OXIDE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 2.0% S in coal;
90% SO_2 removal; sulfuric acid production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, bins, and feeders)	522,000	1.7
Feed preparation (mixer, tank, agitator, and pumps)	241,000	0.8
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorbers to reheater and stack)	5,078,000	16.4
SO_2 absorption (four spray grid towers, including entrainment separators, tanks, agitators, and pumps)	5,425,000	17.5
Stack gas reheat (four indirect steam reheaters)	1,301,000	4.2
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	5,046,000	16.2
Slurry processing (centrifuge, conveyor, tank, agitator, and pumps)	808,000	2.6
Drying (dryer, conveyors, silos, fans, tanks, and pumps)	3,869,000	12.5
Calcining (calciner, cooler, bin, fans, conveyors, and silos)	1,641,000	5.3
Acid production (complete contact unit for sulfuric acid production)	4,334,000	14.0
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	718,000	2.3
Subtotal	29,013,000	93.5
Services, utilities, and miscellaneous	1,741,000	5.6
Total process areas excluding pond construction	30,754,000	99.1
Incremental ash pond cost	300,000	0.9
Total direct investment	31,054,000	100.0
Indirect Investment		
Engineering design and supervision	1,777,000	5.7
Architect and engineering contractor	439,000	1.4
Construction expense	4,342,000	14.0
Contractor fees	1,307,000	4.2
Total indirect investment	7,865,000	25.3
Contingency	7,784,000	25.1
Total fixed investment	46,703,000	150.4
Other Capital Charges		
Allowance for startup and modifications	4,641,000	14.9
Interest during construction	5,604,000	18.1
Total depreciable investment	56,948,000	183.4
Land	42,000	0.1
Working capital	1,118,000	3.6
Total capital investment	58,108,000	187.1

Basis
Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE G-13. MAGNESIUM OXIDE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 2.0% S in coal;
90% SO_2 removal; sulfuric acid production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of annual revenue requirements
Direct Costs				
Delivered raw materials				
MgO	790 tons	300.00/ton	237,000	1.57
Catalyst	990 liters	2.50/liter	2,500	0.02
Agricultural limestone	8,300 tons	15.00/ton	124,500	0.82
Total raw materials cost			364,000	2.41
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	3.31
Utilities				
Fuel oil	3,075,700 gal	0.40/gal	1,230,300	8.14
Steam	429,300 MBtu	2.00/MBtu	858,600	5.68
Process water	1,406,500 kgal	0.12/kgal	168,800	1.12
Electricity	47,269,000 kWh	0.029/kWh	1,370,800	9.07
Heat credit	47,100 MBtu	2.00/MBtu	(94,200)	(0.62)
Maintenance				
Labor and material			2,161,800	14.30
Analyses	2,601 man-hr	17.00/man-hr	44,200	0.29
Total conversion costs			6,240,300	41.29
Total direct costs			6,604,300	43.70
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,416,900	22.61
Average cost of capital and taxes at 8.6% of total capital investment			4,997,300	33.06
Overheads				
Plant, 50% of conversion costs less utilities			1,353,000	8.95
Administrative, 10% of operating labor			50,000	0.33
Marketing, 10% of byproduct sales revenue			145,300	0.96
Total indirect costs			9,962,500	65.91
Gross annual revenue requirements			16,566,800	109.61
Byproduct Sales Revenue				
100% sulfuric acid	58,100 tons	25.00/ton	(1,452,500)	(9.61)
Net annual revenue requirements			15,114,300	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	5.04	12.31	0.56	804

Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,113,400 metric tons/yr (1,227,300 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 17,000 metric tons/yr (18,790 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $31,054,000; total depreciable investment, $56,948,000; and total capital investment, $58,108,000.
All tons shown are 2,000 lb.

TABLE G-14. MAGNESIUM OXIDE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new lignite-fired power unit, 0.5% S in lignite;
90% SO_2 removal; sulfuric acid production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, bins, and feeders)	246,000	1.0
Feed preparation (mixer, tank, agitator, and pumps)	132,000	0.5
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorbers to reheater and stack)	5,271,000	21.2
SO_2 absorption (four spray grid towers, including entrainment separators, tanks, agitators, and pumps)	5,665,000	22.8
Stack gas reheat (four indirect steam reheaters)	1,356,000	5.4
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	5,259,000	21.1
Slurry processing (centrifuge, conveyor, tank, agitator, and pumps)	363,000	1.5
Drying (dryer, conveyors, silos, fans, tanks, and pumps)	2,075,000	8.3
Calcining (calciner, cooler, bin, fans, conveyors, and silos)	738,000	3.0
Acid production (complete contact unit for sulfuric acid production)	1,907,000	7.7
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	323,000	1.3
Subtotal	23,335,000	93.8
Services, utilities, and miscellaneous	1,400,000	5.6
Total process areas excluding pond construction	24,735,000	99.4
Incremental ash pond cost	149,000	0.6
Total direct investment	24,884,000	100.0
Indirect Investment		
Engineering design and supervision	1,594,000	6.4
Architect and engineering contractor	395,000	1.6
Construction expense	3,611,000	14.5
Contractor fees	1,105,000	4.4
Total indirect investment	6,705,000	26.9
Contingency	6,318,000	25.4
Total fixed investment	37,907,000	152.3
Other Capital Charges		
Allowance for startup and modifications	3,776,000	15.2
Interest during construction	4,549,000	18.3
Total depreciable investment	46,232,000	185.8
Land	42,000	0.2
Working capital	841,000	3.4
Total capital investment	47,115,000	189.4

Basis
- Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
- Stack gas reheat to 79°C (175°F) by indirect steam reheat.
- Minimum in-process storage; only pumps are spared.
- Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
- Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE G-15. MAGNESIUM OXIDE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new lignite-fired power unit, 0.5% S in lignite;
90% SO_2 removal; sulfuric acid production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of annual revenue requirements
Direct Costs				
Delivered raw materials				
MgO	250 tons	300.00/ton	75,000	0.60
Catalyst	310 liters	2.50/liter	800	0.01
Agricultural limestone	2,630 tons	15.00/ton	39,500	0.31
Total raw materials cost			115,300	0.92
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	3.98
Utilities				
Fuel oil	951,100 gal	0.40/gal	380,400	3.03
Steam	453,500 MBtu	2.00/MBtu	907,000	7.21
Process water	714,000 kgal	0.12/kgal	85,700	0.68
Electricity	43,330,000 kWh	0.029/kWh	1,256,600	9.99
Heat credit	14,600 MBtu	2.00/MBtu	(29,200)	(0.23)
Maintenance				
Labor and material			1,735,900	13.80
Analyses	1,286 man-hr	17.00/man-hr	21,900	0.17
Total conversion costs			4,858,300	38.63
Total direct costs			4,973,600	39.55
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,773,900	22.06
Average cost of capital and taxes at 8.6% of total capital investment			4,051,900	32.22
Overheads				
Plant, 50% of conversion costs less utilities			1,128,900	8.98
Administrative, 10% of operating labor			50,000	0.40
Marketing, 10% of byproduct sales revenue			44,900	0.36
Total indirect costs			8,049,600	64.02
Gross annual revenue requirements			13,023,200	103.57
Byproduct Sales Revenue				
100% sulfuric acid	17,970 tons	25.00/ton	(449,300)	(3.57)
Net annual revenue requirements			12,573,900	100.00

	Mills/kWh	$/ton lignite burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	6.19	7.36	0.47	2,164

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 5,000 hr/yr.
- Lignite burned, 1,549,900 metric tons/yr (1,708,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
- Stack gas reheat to 79°C (175°F).
- Sulfur removed, 5,270 metric tons/yr (5,810 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $24,884,000; total depreciable investment, $46,232,000; and total capital investment, $47,115,000.
- All tons shown are 2,000 lb.

TABLE G-16. MAGNESIUM OXIDE PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new oil-fired power unit, 2.5% S in oil; 90% SO_2 removal; sulfuric acid production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, bins, and feeders)	471,000	2.0
Feed preparation (mixer, tank, agitator, and pumps)	222,000	0.9
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorbers to reheater and stack)	4,502,000	19.1
SO_2 absorption (four spray grid towers, including presaturators and entrainment separators, tanks, agitators, and pumps)	5,676,000	24.0
Stack gas reheat (four direct oil-fired reheaters)	1,130,000	4.8
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	0	0
Slurry processing (centrifuge, conveyor, tank, agitator, and pumps)	724,000	3.1
Drying (dryer, conveyors, silos, fans, tanks, and pumps)	3,556,000	15.1
Calcining (calciner, cooler, bin, fans, conveyors, and silos)	1,472,000	6.2
Acid production (complete contact unit for sulfuric acid production)	3,873,000	16.4
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	644,000	2.7
Subtotal	22,270,000	94.3
Services, utilities, and miscellaneous	1,336,000	5.7
Total process areas excluding pond construction	23,606,000	100.0
Incremental ash pond cost	-	-
Total direct investment	23,606,000	100.0
Indirect Investment		
Engineering design and supervision	1,347,000	5.7
Architect and engineering contractor	337,000	1.4
Construction expense	3,448,000	14.6
Contractor fees	1,061,000	4.5
Total indirect investment	6,193,000	26.2
Contingency	5,960,000	25.3
Total fixed investment	35,759,000	151.5
Other Capital Charges		
Allowance for startup and modifications	3,576,000	15.1
Interest during construction	4,291,000	18.2
Total depreciable investment	43,626,000	184.8
Land	42,000	0.2
Working capital	923,000	3.9
Total capital investment	44,591,000	188.9

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by direct oil-fired reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE G-17. MAGNESIUM OXIDE PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new oil-fired power unit, 2.5% S in oil;
90% SO_2 removal; sulfuric acid production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of annual revenue requirements
Direct Costs				
Delivered raw materials				
MgO	680 tons	300.00/ton	204,000	1.70
Catalyst	850 liters	2.50/liter	2,100	0.02
Agricultural limestone	0 tons	15.00/ton	0	0
Total raw materials cost			206,100	1.72
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	4.17
Utilities				
Fuel oil	5,117,300 gal	0.40/gal	2,046,900	17.09
Steam	0 MBtu	2.00/MBtu	0	0
Process water	1,172,200 kgal	0.12/kgal	140,700	1.17
Electricity	34,232,000 kWh	0.029/kWh	992,700	8.28
Heat credit	40,200 MBtu	2.00/MBtu	(80,400)	(0.67)
Maintenance				
Labor and material			1,652,400	13.79
Analyses	2,363 man-hr	17.00/man-hr	40,200	0.34
Total conversion costs			5,292,500	44.17
Total direct costs			5,499,600	45.89
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,617,600	21.84
Average cost of capital and taxes at 8.6% of total capital investment			3,834,800	32.0
Overheads				
Plant, 50% of conversion costs less utilities			1,096,300	9.15
Administrative, 10% of operating labor			50,000	0.42
Marketing, 10% of byproduct sales revenue			123,800	1.03
Total indirect costs			7,722,500	64.44
Gross annual revenue requirements			13,222,100	110.33
Byproduct Sales Revenue				
100% sulfuric acid	49,500 tons	25.00/ton	(1,237,500)	(10.33)
Net annual revenue requirements			11,984,600	100.00

	Mills/kWh	$/bbl oil burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	3.99	2.68	0.44	748

Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Oil burned, 710 x 10^6 liters/yr (4,464,300 bbl/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 14,530 metric tons/yr (16,020 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $23,606,000; total depreciable investment, $43,626,000; and total capital investment, $44,591,000.
All tons shown are 2,000 lb.

APPENDIX H

SODIUM SULFITE PROCESS (WELLMAN-LORD)

PROCESS DESCRIPTION

The Wellman-Lord process is a sodium sulfite-based scrubbing process that produces SO_2. The SO_2 can be liquefied, or processed to sulfuric acid or elemental sulfur. The system evaluated is Wellman-Lord scrubbing combined with a sulfuric acid plant. An additional case variation is included that uses an Allied Chemical methane reduction unit for sulfur production. The flow diagram is shown in Figure H-1. The base-case material balance and equipment list are shown in Tables H-1 and H-2. The flue gas from the common plenum enters a chloride scrubber where the gas is cooled and the chlorides are removed. From this scrubber the flue gas passes countercurrently to a recirculating sodium sulfite solution in a three-stage valve tray absorber where the SO_2 reacts with the sodium sulfite to form sodium bisulfite and a very small amount of sodium sulfate. Liquor is individually recirculated in each of the three stages to maintain efficient mass transfer. Each absorber has a chevron-type entrainment separator to control entrainment carryover in the gas stream.

A portion of the scrubber effluent is processed to remove Na_2SO_4 by evaporation and selective crystallization in a steam-heated, forced-circulation evaporator serving all four scrubber trains. The clear overflow, enriched in $NaHSO_3$, is returned to the regeneration area. The bottoms, consisting of a slurry enriched in Na_2SO_4 crystals, are centrifuged to produce a solid containing about two-thirds Na_2SO_4 and one-third Na_2SO_3. The centrate is returned to the regeneration area; the solids are dried in a steam-heated dryer and conveyed to a storage silo for sale or discard. There is a potential market available in the paper industry for this material.

The regeneration system consists of two trains of double-effect, forced-circulation evaporators. Scrubber effluent, combined with liquid from the sulfate removal process, is heated and 60% is pumped to the first-effect evaporators and 40% to the second-effect evaporators. The first effect is steam heated; the second effect is heated by combined first-effect vapor and sulfate crystallizer vapor. Some $Na_2S_2O_3$ formed in the first-effect evaporator is removed by a purge stream. Evaporator and stripper overhead vapor, containing H_2O and SO_2, is dried and compressed. The concentrated SO_2 stream is routed to a processing plant. SO_2-bearing condensate from the second-effect evaporator heater, the condensers, and the compressor is steam stripped and combined with evaporator bottoms. The resulting mixture, enriched in Na_2SO_3, is returned to the absorber system.

The concentrated SO_2 stream is converted to H_2SO_4 in a single-contact, single absorption acid plant. The tail gas containing unreacted SO_2 is returned to the scrubber. The Allied Chemical methane reduction process is used for a sulfur production case variation. In this process, about 60% of the SO_2 from the Wellman-Lord plant is reduced directly to elemental sulfur by reaction with methane in a primary reduction reactor. Gas leaving the primary reactor, containing H_2S and SO_2 in a molar ratio of 2:1, is routed to a catalytic Claus converter where total conversion of SO_2 to S is increased to about 95%. Sulfur condensed from the gas stream after the primary and secondary reactors, is pumped to storage. Noncondensed gases from the last sulfur condenser are pumped to an incinerator to oxidize remaining sulfur compounds back to SO_2. After incineration the gases are recycled back to the SO_2 absorbers.

SPECIFIC PROCESS PREMISES

1. The flue gas is cooled from 149°C (300°F) to 54°C (130°F) in the chloride scrubber at an L/G ratio of 1.3 liters/m^3 (10 gal/10^3 aft^3).

2. A 3-stage valve tray absorber with 2 chimney trays and a superficial velocity of 3 m/sec (10 ft/sec), an L/G ratio of 0.4 liter/m^3 (3 gal/10^3 aft^3), and a pressure drop, including the mist eliminator of 2.9 kPa (11.6 in. H_2O).

3. Stoichiometry is 2.0 mole of Na_2CO_3 to 1.0 mole of Na removed in the sulfate purge stream.

ENERGY REQUIREMENTS

For base-case conditions, reheat of the cleaned gas requires 36.2 x 10^3 kg/hr (79,700 lb/hr) of 243°C (470°F) steam at 3.55 x 10^3 kPa absolute pressure (500 psig), equivalent to about 15.1 x 10^6 kcal/hr. In the purge area, the sulfate dryer uses 0.7 x 10^3 kg/hr (1,600 lb/hr) of 243°C (470°F) saturated steam and the sulfate crystallizer uses 10.3 x 10^3 kg/hr (22,800 lb/hr) of 121°C (250°F) steam at 2.10 x 10^3 kPa (15 psig) absolute pressure. Total consumption in the purge area is equivalent to 6.1 x 10^6 kcal/hr. Steam consumption for the first effect evaporators and the stripper in the regeneration area is 70.4 kg/hr (155,100 lb/hr) of 121°C (250°F) saturated steam, equivalent to 40.5 x 10^6 kcal/hr. The acid plant produces 3.6 x 10^3 kg/hr (7,900 lb/hr) of 121°C (250°F) saturated steam, equivalent to 1.98 x 10^6 kcal/hr. This is taken into account as a heat credit for the process.

The electrical power demand for the base case is about 11,300 kW or 2.3% of the rated capacity of a 500-MW power plant. For 6,000 hours of operation, the annual electrical energy consumption is 68.1 x 10^6 kWh.

The total equivalent energy consumption for the base case is approximately 92.35 x 10^6 kcal/hr or 8.1% of the input energy required for the 500-MW power unit. Summarized energy requirements for all cases are listed in Table H-3.

BYPRODUCT MANAGEMENT

Electrostatic precipitators remove 99.2% of the fly ash in the flue gas. Most of the remainder is removed in the chloride scrubber; therefore, it is assumed that the byproducts contain little, if any, fly ash. (Fly ash emission from oil-fired units does not exceed the EPA particulate emission standard and fly ash collection facilities are not included in oil-fired power plant design.) Projected mass flow rates of byproduct streams for the base case are shown below.

	Component	kg/hr	lb/hr
Sulfuric acid:	98% H_2SO_4	15,100	33,300
Sodium sulfate:	Na_2SO_4	680	1,500
	Na_2SO_3	450	1,000
	Other Na salts	50	100
Total		1,180	2,600
Chloride purge:	HCl	290	630
	SO_3	40	80
	Ash	150	330

The byproduct sulfuric acid is stored in a tank of 30-day capacity until sold. For the purposes of this study the sodium sulfate is assumed to be sold.

ECONOMIC EVALUATION

Capital investment and annual revenue requirement summaries for the base case, five fuel variations, and a case variation with sulfur production are shown in Tables H-4 and H-5. Detailed results are shown in Tables H-6 through H-19. The results showing the range of estimated accuracies are also shown graphically in Figures H-2 and H-3. The effect of fuel sulfur content on cost is shown in Figure H-4.

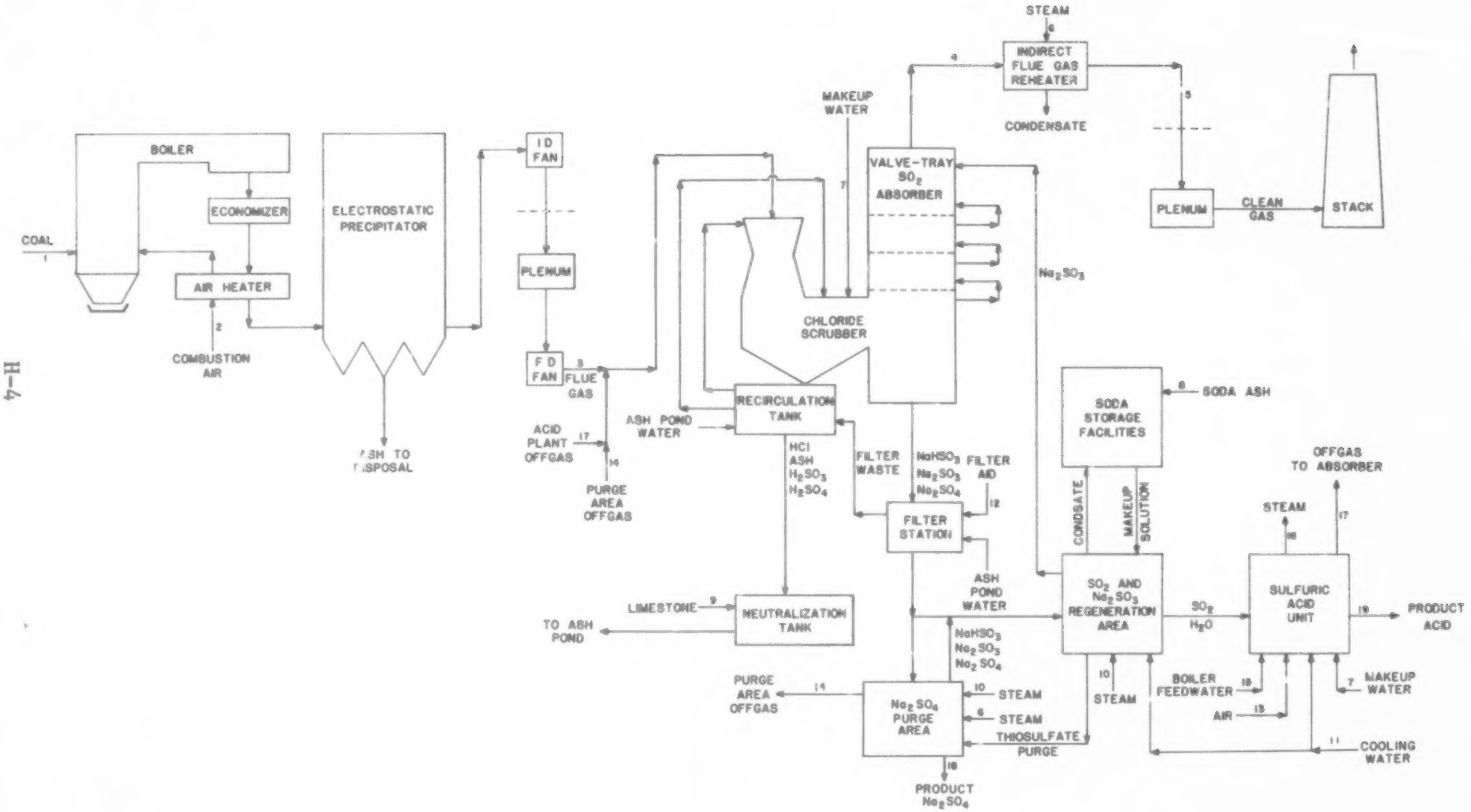
STEAM
6
INDIRECT FLUE GAS REHEATER
4
5
CONDENSATE
MAKEUP WATER
7
BOILER
ECONOMIZER
COAL
1
AIR HEATER
2
COMBUSTION AIR
ELECTROSTATIC PRECIPITATOR
ASH TO DISPOSAL
ID FAN
PLENUM
F D FAN
3
FLUE GAS
ACID PLANT OFFGAS
17
14
PURGE AREA OFFGAS
VALVE-TRAY SO_2 ABSORBER
CHLORIDE SCRUBBER
Na_2SO_3
PLENUM
CLEAN GAS
STACK
RECIRCULATION TANK
ASH POND WATER
HCl
ASH
H_2SO_3
H_2SO_4
FILTER WASTE
$NaHSO_3$
Na_2SO_3
Na_2SO_4
FILTER AID
12
FILTER STATION
ASH POND WATER
LIMESTONE
9
NEUTRALIZATION TANK
TO ASH POND
SODA STORAGE FACILITIES
6
SODA ASH
CONDSATE
MAKEUP SOLUTION
SO_2 AND Na_2SO_3 REGENERATION AREA
10
STEAM
SO_2
H_2O
SULFURIC ACID UNIT
STEAM
16
OFFGAS TO ABSORBER
17
19
PRODUCT ACID
BOILER FEEDWATER
18
AIR
13
7
MAKEUP WATER
11
COOLING WATER
$NaHSO_3$
Na_2SO_3
Na_2SO_4
PURGE AREA OFFGAS
14
Na_2SO_4 PURGE AREA
10
STEAM
6
STEAM
THIOSULFATE PURGE
18
PRODUCT Na_2SO_4

Figure H-1. Wellman-Lord process flow diagram.

TABLE H-1. WELLMAN-LORD/SULFURIC ACID PROCESS

MATERIAL BALANCE - BASE CASE (3.5% SULFUR COAL)

	Stream No.	1	2	3	4	5
	Description	Coal to boiler	Combustion air to air heater	Flue gas to chloride scrubber	Gas to reheater	Gas to stack
1	Total stream, 1000 kg/hr	194	2,062	2,225	2,349	2,349
2	Total stream, lb/hr	428,600	4,546,200	4,906,000	5,178,300	5,178,300
3	Gas flow, Nm^3/hr (0°C)		1,615,700	1,697,700	1,839,100	1,842,000
4	Gas flow, sft^3/min (60°F)		1,005,000	1,056,000	1,143,700	1,145,500
5	Liquid flow, liters/min				39	
6	Liquid flow, gal/min				10	
7	Temperature, $^\circ$C		27	149	57	79
8	Particulates, kg/hr			199.1	49.8	49.8
9	Particulates, lb/hr			439	110	110
10						

	Stream No.	6	7	8	9	10
	Description	Steam to reheat and purge area	Process makeup water	Makeup soda ash to storage	Limestone to neutralization tank	Process steam
1	Total stream, 1000 kg/hr	36.9	106	0.9	0.4	80.7
2	Total stream, lb/hr	81,300	233,600	2,050	930	177,900
3	Gas flow, Nm^3/hr (0°C)					
4	Gas flow, sft^3/min (60°F)					
5	Liquid flow, liters/min		1,767			
6	Liquid flow, gal/min		467			
7	Temperature, $^\circ$C	243				121
8	Pressure, Pascals (abs)	3.55×10^6				2.07×10^5
9	Pressure, psig	500				15
10						

	Stream No.	11	12	13	14	15
	Description	Cooling water	*Filter aid	Oxidation air to acid plant	Purge area off-gas	Boiler feedwater to acid plant
1	Total stream, 1000 kg/hr	3,015		40.5	0.4	3.6
2	Total stream, lb/hr	6,646,700	(100)	89,200	1,000	7,900
3	Gas flow, Nm^3/hr (0°C)			31,700	510	
4	Gas flow, sft^3/min (60°F)			19,700	320	
5	Liquid flow, liters/min	50,300				60
6	Liquid flow, gal/min	13,300				16
7	Temperature, $^\circ$C	27		27	132	82
8	Pressure, Pascals (abs)					
9	Pressure, psig					
10						

*Intermittent stream

	Stream No.	16	17	18	19	
	Description	Steam to steam plant	Acid plant off-gas	Product sodium sulfate	Product sulfuric acid (98% H_2SO_4)	
1	Total stream, 1000 kg/hr	3.6	33.1	1.2	15.1	
2	Total stream, lb/hr	7,900	73,000	2,600	33,300	
3	Gas flow, Nm^3/hr (0°C)		25,700			
4	Gas flow, sft^3/min (60°F)		16,000			
5	Liquid flow, liters/min				138	
6	Liquid flow, gal/min				36.5	
7	Temperature, $^\circ$C	121	77			
8	Pressure, Pascals (abs)	2.07×10^5				
9	Pressure, psig	15				
10	Specific gravity				1.82	

TABLE H-2. WELLMAN-LORD PROCESS

BASE-CASE EQUIPMENT LIST DESCRIPTION AND COST

Area 1--Materials Handling			Area size-cost exponent 0.62	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Car shaker	1	Top mounting with crane	9,000	2,100
2. Tank, soda ash storage	1	34 ft dia x 35 ft high, 237,730 gal, w/cover, carbon steel, insulated, 3 spargers in bottom (30 day storage capacity)	42,100	66,600
3. Pump, soda ash feed	2	Centrifugal, 10 gpm, 60 ft head, 1.0 hp, carbon steel (1 operating, 1 spare)	3,300	1,200
4. Dust collecting system	1	Bag filter, polypropylene bag, 4,000 aft^3/min, automatic shaker system	13,300	3,300
5. Conveyor, limestone	1	Pneumatic, pressure, 75 hp	51,800	12,200
6. Silo, limestone storage	1	19 ft dia x 29 ft straight side, 8,200 ft^3, 60° slope, 3/8 in. carbon steel	13,000	33,000
7. Bin, limestone feed	1	5-1/2 ft dia x 8-1/2 straight side height, w/cover, carbon steel	1,500	2,200
Subtotal			134,000	120,600

Area 2--Feed Preparation

No equipment in this area.

(continued)

TABLE H-2 (continued)

Area 3--Gas Handling			Area size-cost exponent 0.68	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Fans	4	Forced draft, 19.7 in. static head, 1,750 hp, fluid drive, double width, double inlet	1,705,400	97,600
Subtotal			1,705,400	97,600

Area 4--SO_2 Absorption			Area size-cost exponent 0.86	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. SO_2 absorber	4	Valve tray, 24 ft x 24 ft x 50 ft high, concrete, tile lined, 3-316 stainless steel valve trays, 2-316 stainless steel chimney trays, 1-316 stainless steel mist eliminator	1,414,400	564,800
2. Pump, SO_2 absorber recirculation	16	Centrifugal, 550 gpm, 20 ft head, 10 hp, carbon steel, neoprene lined (12 operating, 4 spare)	60,700	12,600
3. Pump, absorber effluent	6	Centrifugal, 170 gpm, 200 ft head, 25 hp, carbon steel, neoprene lined (4 operating, 2 spare)	49,200	9,500
4. Filter, absorber product	2	Pressure leaf, 60 in. dia x 11 ft long, 28 vertical leaves, 316 stainless steel, insulated	202,800	102,800
5. Sump, effluent	1	8 ft x 8 ft x 8 ft deep, concrete, tile lined, grating covered	7,000	8,000

(continued)

TABLE H-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
6. Agitator, effluent sump	1	32 in. dia, 2 hp, neoprene coated	6,200	700
7. Pump, effluent sump	2	Centrifugal, submerged, 100 gpm, 60 ft head, 5 hp, carbon steel, neoprene lined (1 operating, 1 spare)	5,300	1,500
8. Tank, absorber product	1	57 ft dia x 57 ft high, 1,088,100 gal, w/cover, concrete, tile lined, insulated (24 hr residence time)	168,700	112,500
9. Pump, absorber product tank	2	Centrifugal, 680 gpm, 100 ft head, 50 hp, carbon steel, neoprene lined (1 operating, 1 spare)	11,600	3,700
10. Heater, absorber product	1	Plate and frame type heat exchanger, 400 ft^2, 316 stainless steel, insulated	9,100	2,300
11. Soot blowers	40	Air, retractable	260,000	225,800
Subtotal			2,195,000	1,044,200

Area 5--Reheat

Area size-cost exponent 0.75

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Reheaters	4	Steam, tube type, 3,170 ft^2, one-half tubes made of Inconel 625 and one-half made of Cor-Ten	787,200	37,200
2. Soot blowers	20	Air, retractable	130,000	112,900
Subtotal			917,200	150,100

(continued)

TABLE H-2 (continued)

Area 6--Chloride Removal			Area size-cost exponent 0.75	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Chloride scrubber	4	Venturi-spray chamber combination, venturi: 13 ft dia x 25 ft overall height, variable throat, carbon steel, elastomer and tile lined, Hastelloy® G throat Spray chamber: 24 ft x 20 ft x 11 ft high, carbon steel, elastomer and tile lined, Hastelloy® G nozzles with stellite tips; Hastelloy® G mist eliminator	1,834,200	439,200
2. Tank, recirculation	4	20 ft dia x 6 ft high, 14,100 gal, w/cover, four 20 in. baffles, agitator supports, carbon steel, insulated (10 min residence time)	14,100	26,900
Lining		1/4 in. neoprene lining	15,300	18,700
3. Agitator, recirculation tank	4	80 in. dia, 1-1/2 hp, neoprene coated	15,200	2,200
4. Pump, venturi recirculation	6	Centrifugal, 3,140 gpm, 60 ft head, 100 hp, carbon steel, neoprene lined (4 operating, 2 spare)	88,700	23,900
5. Pump, spray chamber recirculation	6	Centrifugal, 3,140 gpm, 150 ft head, 250 hp, carbon steel, neoprene lined (4 operating, 2 spare)	159,400	28,300
6. Tank, neutralization	1	11-1/2 ft dia x 6 ft high, 4,660 gal, w/cover, four 11-1/2 in. baffles, agitator supports, carbon steel, insulated (30 min residence time)	1,300	3,500
Lining		1/4 in. neoprene lining	1,400	1,800

(continued)

TABLE H-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
7. Agitator, neutralization tank	1	46 in. dia, 1 hp, neoprene coated	2,700	500
8. Pump, pond feed	2	Centrifugal, 130 gpm, 150 ft head, 15 hp, carbon steel, neoprene lined (1 operating, 1 spare)	11,200	3,000
9. Pump, pond water return	2	Centrifugal, 300 gpm, 150 ft head, 25 hp, carbon steel, neoprene lined (1 operating, 1 spare)	16,200	5,900
10. Feeder, limestone feedbin discharge	1	Weigh, screw, 6 in. dia x 10 ft long, 1 hp, 900 lb/hr	5,300	200
11. Pump, raw water	2	Centrifugal, 650 gpm, 150 ft head, 60 hp, carbon steel (1 operating, 1 spare)	18,200	6,000
12. Pump, chloride scrubber water booster	2	Centrifugal, 450 gpm, 150 ft head, 40 hp, carbon steel (1 operating, 1 spare)	17,000	5,900
Subtotal			2,200,200	566,000

Area 7--Sulfate Crystallization

Area size-cost exponent 0.66

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Preheater, crystallizer feed	1	Plate and frame type, 90 ft^2, 316 stainless steel, insulated	3,900	1,100
2. Crystallizer, sulfate	1	9 ft dia x 12 ft straight side, 316 stainless steel, insulated (package price includes heater, recirculation pump, and recirculation piping)	651,800	66,800

(continued)

TABLE H-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
3. Receiver, condensate	1	2-1/2 ft dia x 3 ft high, 110 gal, w/cover, carbon steel, insulated (2 min residence time)	300	500
4. Pump, condensate	2	Centrifugal, 45 gpm, 60 ft head, 2 hp, carbon steel, (1 operating, 1 spare)	3,400	1,200
5. Pump, centrifuge feed	2	Centrifugal, 9 gpm, 60 ft head, 3/4 hp, 316 stainless steel (1 operating, 1 spare)	4,800	1,500
6. Centrifuge	1	Solid bowl, continuous, 40 hp, 316 stainless steel	90,800	10,000
7. Tank, centrate	1	5 ft dia x 6 ft high, 880 gal, w/cover, four 5-in. baffles, agitator supports, 316 stainless steel, insulated (10 min residence time)	2,700	1,900
8. Agitator, centrate tank	1	Two turbines, 20 in. dia, 1-1/2 hp, 316 stainless steel	3,800	600
9. Pump, centrate tank	2	Centrifugal, 80 gpm, 100 ft head, 7-1/2 hp, 316 stainless steel (1 operating, 1 spare)	11,700	1,800
10. Dryer	1	Porcupine processor, twin screw, 316 stainless steel, insulated	262,200	27,300
11. Dust collecting system	1	Bag filter, polypropylene bag, 520 aft^3/min, automatic shaker system	9,000	2,200
12. Hopper, sulfate surge	1	6-1/2 ft dia x 10 ft high, 330 ft^3, w/cover, carbon steel	4,600	3,600

(continued)

TABLE H-2 (continued)

	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
13.	Conveyor, sulfate	1	Pneumatic, pressure, 15 hp	31,300	8,000
14.	Silo, sulfate storage	1	29 ft dia x 44 ft straight side height, 29,100 ft^3, 60^o slope, 3/8 in. carbon steel (30 day storage capacity)	55,500	121,200
15.	Feeder, sulfate silo discharge	1	Vibrating pan, 2 hp, 120 tons/hr	3,800	100
	Subtotal			1,139,600	247,800

Area 8--Regeneration

Area size-cost exponent 0.70

	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1.	Preheater, first effect evaporator feed	1	Plate and frame type, 340 ft^2, 316 stainless steel, insulated	6,800	1,600
2.	Preheater, second effect evaporator feed	1	Plate and frame, 100 ft^2, 316 stainless steel, insulated	4,600	1,400
3.	Evaporator system, double effect unit.	2	17 ft dia x 17 ft straight side, 316 stainless steel (package price includes heaters, recirculation pumps, and recirculation piping)	3,000,000	300,000
4.	Receiver, first effect condensate	2	3-1/2 ft dia x 4-1/2 ft high, 320 gal, w/cover, carbon steel, insulated (2 min residence time)	1,200	1,900

(continued)

TABLE H-2 (continued)

	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
5.	Receiver, second effect condensate	2	3 ft dia x 4-1/2 ft high, 240 gal, w/cover, 316 stainless steel, insulated (2 min residence time)	2,500	1,700
6.	Pump, first effect condensate	4	Centrifugal, 145 gpm, 60 ft head, 7-1/2 hp, carbon steel (2 operating, 2 spare)	11,200	3,000
7.	Pump, second effect condensate	4	Centrifugal, 110 gpm, 60 ft head, 5 hp, 316 stainless steel (2 operating, 2 spare)	22,800	3,600
8.	Tank, dissolving	1	15-1/2 ft dia x 15-1/2 ft high, 21,880 gal, w/cover, four 15-1/2 in. baffles, agitator supports, carbon steel, insulated (30 min residence time)	11,000	16,600
	Lining		1/4 in. neoprene lining	6,400	7,800
9.	Agitator, dissolving tank	1	Two turbines, 58 in. dia, 7-1/2 hp, neoprene coated	12,000	1,000
10.	Pump, dissolving tank	2	Centrifugal, 660 gpm, 100 ft head, 50 hp, carbon steel, neoprene lined (1 operating, 1 spare)	11,600	3,800
11.	Separator, mother liquor	2	4 ft dia x 2 ft straight side, 60° slope, 316 stainless steel, insulated	3,800	2,600
12.	Pump, mother liquor	2	Centrifugal, 2 gpm, 60 ft head, 1/2 hp, 316 stainless steel (1 operating, 1 spare)	3,300	1,200

(continued)

TABLE H-2 (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
13. Tank, absorber feed	1	57 ft dia x 57 ft high, 1,088,100 gal, w/cover, concrete, tile lined, insulated	168,700	112,500
14. Pump, absorber feed tank	2	Centrifugal, 660 gpm, 100 ft head, 50 hp, carbon steel, neoprene lined (1 operating, 1 spare)	11,600	3,800
15. Stripper	1	5 ft dia x 20 ft overall height, 316 stainless steel, insulated	12,100	7,000
16. Pump, stripper bottoms	2	Centrifugal, 530 gpm, 100 ft head, 30 hp, carbon steel, neoprene lined (1 operating, 1 spare)	9,600	3,000
17. Condenser, primary	2	Shell and tube type, 5,800 ft^2, 316 stainless steel tubes, heads, and shell	141,300	141,300
18. Condenser, secondary	2	Shell and tube type, 4,700 ft^2, 316 stainless steel tubes, heads, and shell	121,500	121,500
19. Pump, cooling water	3	Centrifugal, 5,450 gpm, 150 ft head, 450 hp, carbon steel (2 operating, 1 spare)	101,700	15,000
20. Blower, product gas	1	Centrifugal, single stage, 15,400 aft^3/min, 600 hp, 316 stainless steel	203,900	61,200
21. Tank, central condensate	1	9 ft dia x 8-1/2 ft high, 4,050 gal, w/cover, carbon steel, insulated (10 min residence time)	3,100	4,700
22. Pump, condensate return	2	Centrifugal, 360 gpm, 150 ft head, 30 hp, carbon steel, (1 operating, 1 spare)	16,200	5,900
Subtotal			3,886,900	822,100

(continued)

TABLE H-2 (continued)

Area 9--98% Sulfuric Acid Production — Area size-cost exponent 0.70

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Complete H_2SO_4 unit	1	Complete 98% sulfuric acid unit, battery limits	6,138,000	-
Subtotal			6,138,000	

Area 10--Acid Storage and Shipping — Area size-cost exponent 0.68

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Tank, acid storage	2	51 ft dia x 53 ft high, 810,000 gal, w/cover, carbon steel, insulated (30 day capacity)	207,600	320,400
2. Pump, acid storage tank discharge	2	Centrifugal, 400 gpm, 100 ft head, 40 hp, carbon steel (1 operating, 1 spare)	10,500	3,100
Subtotal			218,100	323,500

TABLE H-3. WELLMAN-LORD PROCESS ENERGY REQUIREMENTS

Case	Reheat, kcal/hr	Electricity, kcal/hr (kW)	Process steam, kcal/hr	Oil, kcal/hr	Natural gas, kcal/hr	Heat credit, kcal/hr	Total equivalent energy consumption,[a] % of input energy
500-MW unit							
Coal, 3.5% S (base case)	15.10 M	25.73 M (11,343)	46.64 M	-	-	1.98 M	8.14
Coal, 0.8% S	15.47 M	17.99 M (7,934)	10.90 M	-	-	0.46 M	4.13
Coal, 1.4% S	14.95 M	18.68 M (8,236)	16.19 M	-	-	0.69 M	4.64
Coal, 2.0% S	15.02 M	20.90 M (9,215)	25.68 M	-	-	1.09 M	5.73
Lignite, 0.5% S	15.87 M	17.72 M (7,812)	7.94 M	-	-	0.34 M	3.87
Oil, 2.5% S	12.57 M	15.44 M (6,807)	21.90 M	-	-	0.93 M	4.53
Coal, 3.5% S (sulfur production)	15.10 M	25.59 M (11,282)	47.20 M	-	20.56 M	2.79 M	9.93

a. Based on boiler efficiency of 90% for generation of steam and a gross heat rate of 9,000 Btu/kWh for generation of electricity.

TABLE H-4. WELLMAN-LORD PROCESS CAPITAL INVESTMENT

Case	Total capital investment $	 $/kW
500-MW unit		
Coal, 3.5% S (base case)	68,722,000	137
Coal, 0.8% S	46,836,000	94
Coal, 1.4% S	50,307,000	101
Coal, 2.0% S	56,939,000	114
Lignite, 0.5% S	44,837,000	90
Oil, 2.5% S	44,215,000	88
Coal, 3.5% S (sulfur production)	71,342,000	143

TABLE H-5. WELLMAN-LORD PROCESS ANNUAL REVENUE REQUIREMENTS

Case	$	Mills/kWh	$/ton coal (bbl oil) burned	$/MBtu heat input	$/ton S removed
500-MW unit					
Coal, 3.5% S (base case)	17,886,400	5.96	13.91	0.66	524
Coal, 0.8% S	12,218,300	4.07	8.60	0.45	1,531
Coal, 1.4% S	13,081,000	4.36	12.21	0.48	1,104
Coal, 2.0% S	14,802,200	4.93	12.06	0.55	788
Lignite, 0.5% S	11,754,700	3.92	6.88	0.44	2,023
Oil, 2.5% S	11,801,900	3.93	(2.64)	0.44	737
Coal, 3.5% S (sulfur production)	21,015,700	7.00	16.34	0.78	616

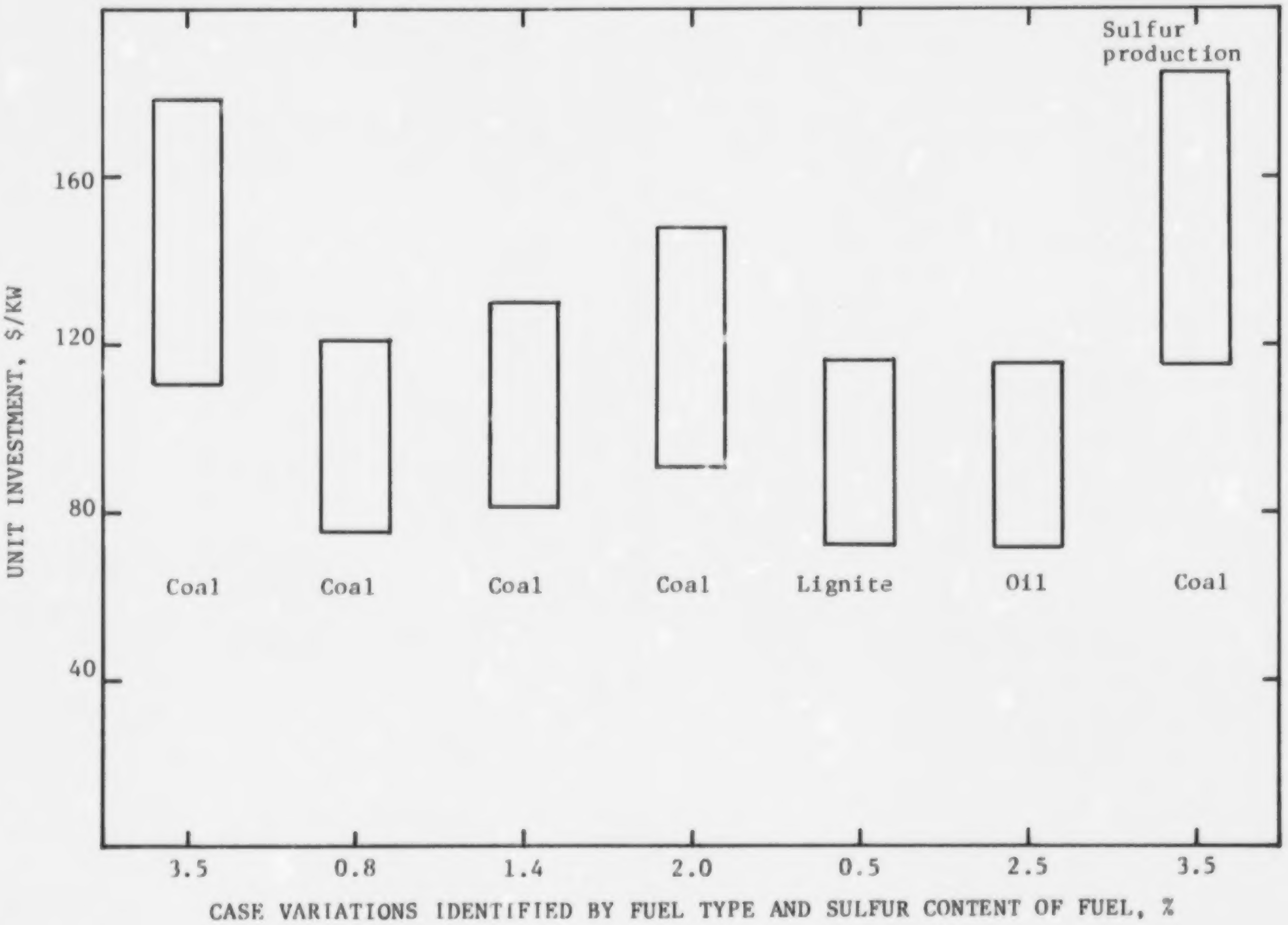

Figure H-2. Wellman-Lord process unit investment range.

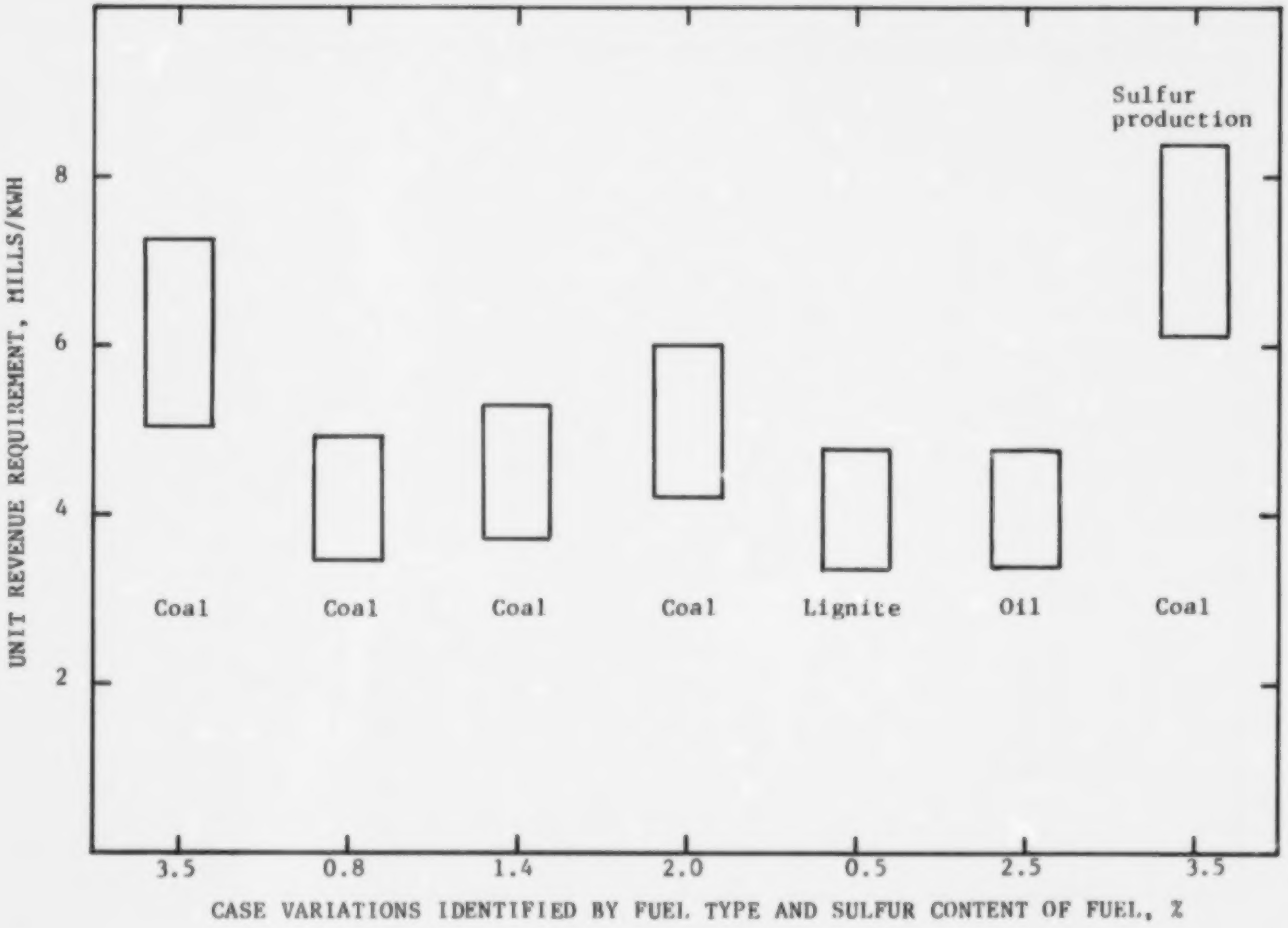

Figure H-3. Wellman-Lord process unit revenue requirement range.

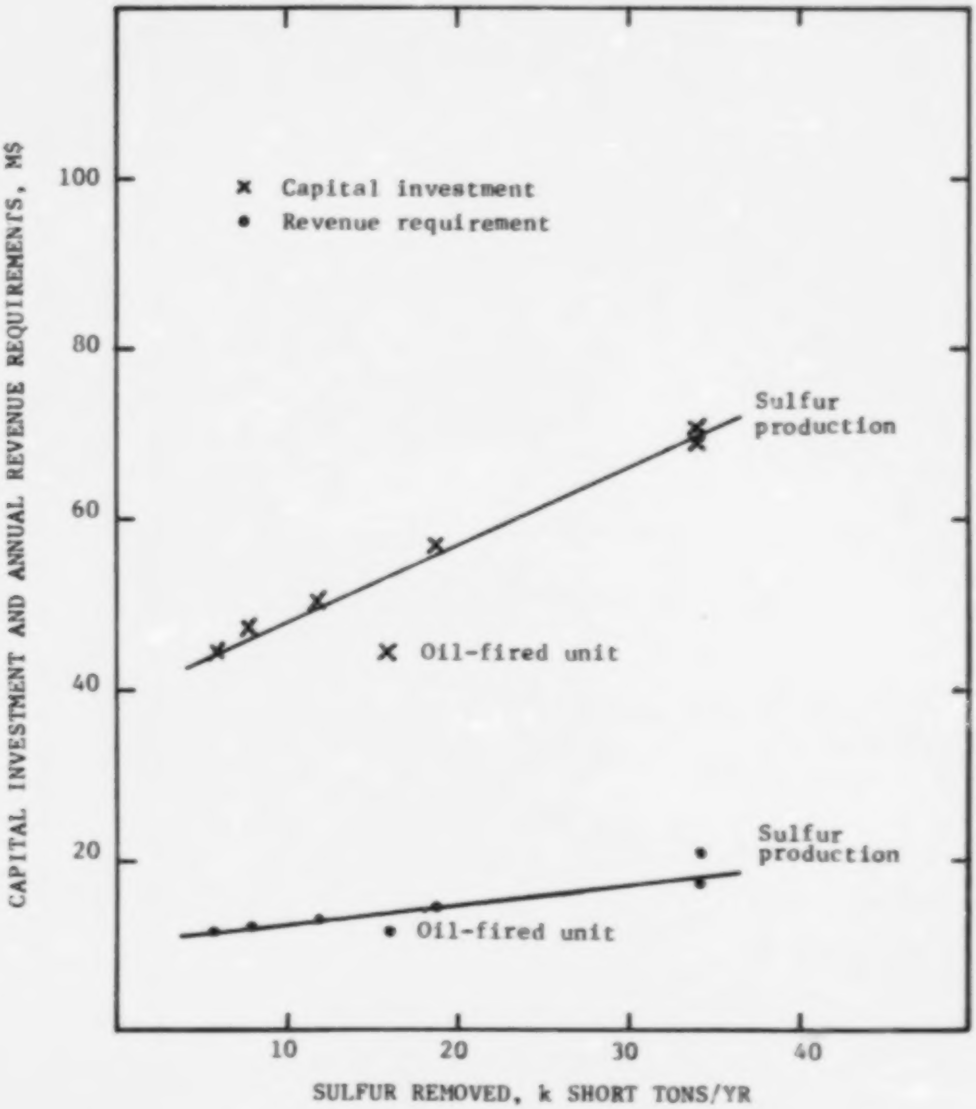

Figure H-4. Wellman-Lord process. Effect of sulfur removed on total capital investment and annual revenue requirement.

TABLE H-6. WELLMAN-LORD PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; sulfuric acid production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	503,000	1.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,861,000	13.3
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,595,000	12.5
Stack gas reheat (four indirect steam reheaters)	1,221,000	3.3
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,894,000	13.4
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	2,934,000	8.0
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	8,297,000	22.6
Acid production (complete contact unit for sulfuric acid production)	6,138,000	16.8
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	978,000	2.7
Subtotal	34,421,000	94.0
Services, utilities, and miscellaneous	2,065,000	5.6
Total excluding pond	36,486,000	99.6
Pond	154,000	0.4
Total direct investment	36,640,000	100.0
Indirect Investment		
Engineering design and supervision	2,271,000	6.2
Architect and engineering contractor	565,000	1.5
Construction expense	4,976,000	13.6
Contractor fees	1,482,000	4.0
Total indirect investment	9,294,000	25.3
Contingency	9,187,000	25.1
Total fixed investment	55,121,000	150.4
Other Capital Charges		
Allowance for startup and modifications	5,497,000	15.0
Interest during construction	6,614,000	18.1
Total depreciable investment	67,232,000	183.5
Land	28,000	0.1
Working capital	1,462,000	4.0
Total capital investment	68,722,000	187.6

Basis
- Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
- Stack gas reheat to 79°C (175°F) by indirect steam reheat.
- Minimum in-process storage; only pumps are spared.
- Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
- Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE H-7. WELLMAN-LORD PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; sulfuric acid production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	6,150 tons	103.00/ton	633,500	3.54
Catalyst	1,760 liters	2.50/liter	4,400	0.02
Agricultural limestone	2,780 tons	15.00/ton	41,700	0.23
Filter aid	70 tons	189.00/ton	13,200	0.07
Total raw material cost			692,800	3.86
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	2.80
Utilities				
Steam	1,469,900 MBtu	2.00/MBtu	2,939,800	16.44
Process water	4,950,800 kgal	0.12/kgal	594,100	3.32
Electricity	68,060,600 kWh	0.029/kWh	1,973,800	11.04
Heat credit	47,200 MBtu	2.00/MBtu	(94,400)	(0.53)
Maintenance				
Labor and material			2,193,800	12.27
Analyses	3,720 man-hr	17.00/man-hr	65,100	0.36
Total conversion costs			8,172,200	45.70
Total direct costs			8,865,000	49.56
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,033,900	22.55
Average cost of capital and taxes at 8.6% of total capital investment			5,910,100	33.05
Overheads				
Plant, 50% of conversion cost less utilities			1,379,500	7.71
Administrative, 10% of operating labor			58,100	0.32
Marketing, 10% of byproduct sales revenue			262,200	1.47
Total indirect costs			11,643,800	65.10
Gross annual revenue requirements			20,508,800	114.66
Byproduct Sales Revenue				
100% sulfuric acid	97,710 tons	25.00/ton	(2,442,800)	(13.66)
Sodium sulfate	7,810 tons	23.00/ton	(179,600)	(1.00)
Net annual revenue requirements			17,886,400	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	5.96	13.91	0.66	524

Basis

Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,166,200 metric tons/yr (1,285,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 30,950 metric tons/yr (34,120 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $36,640,000; total depreciable investment, $67,232,000; and total capital investment, $68,722,000.
All tons shown are 2,000 lb.

TABLE H-8. WELLMAN-LORD PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 0.8% S in coal;
90% SO_2 removal; sulfuric acid production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	204,000	0.8
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,944,000	20.4
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,691,000	19.3
Stack gas reheat (four indirect steam reheaters)	1,243,000	5.1
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,982,000	20.6
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	1,124,000	4.6
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	3,004,000	12.4
Acid production (complete contact unit for sulfuric acid production)	2,222,000	9.1
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	364,000	1.5
Subtotal	22,778,000	93.8
Services, utilities, and miscellaneous	1,367,000	5.6
Total excluding pond	24,145,000	99.4
Pond	156,000	0.6
Total direct investment	24,301,000	100.0
Indirect Investment		
Engineering design and supervision	1,997,000	8.2
Architect and engineering contractor	496,000	2.0
Construction expense	3,561,000	14.6
Contractor fees	1,085,000	4.5
Total indirect investment	7,119,000	29.3
Contingency	6,284,000	25.9
Total fixed investment	37,704,000	155.2
Other Capital Charges		
Allowance for startup and modifications	3,755,000	15.4
Interest during construction	4,524,000	18.6
Total depreciable investment	45,983,000	189.2
Land	28,000	0.1
Working capital	825,000	3.4
Total capital investment	46,836,000	192.7

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE H-9. WELLMAN-LORD PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 0.8% S in coal;
90% SO_2 removal; sulfuric acid production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	1,440 tons	103.00/ton	148,300	1.21
Catalyst	410 liters	2.50/liter	1,000	0.01
Agricultural limestone	2,850 tons	15.00/ton	42,800	0.35
Filter aid	15 tons	189.00/ton	2,800	0.02
Total raw material cost			194,900	1.59
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	4.09
Utilities				
Steam	627,900 MBtu	2.00/MBtu	1,255,800	10.28
Process water	1,286,400 kgal	0.12/kgal	154,400	1.26
Electricity	47,601,500 kWh	0.029/kWh	1,380,400	11.30
Heat credit	11,000 MBtu	2.00/MBtu	(22,000)	(0.18)
Maintenance				
Labor and material			1,453,400	11.90
Analyses	1,555 man-hr	17.00/man-hr	26,400	0.22
Total conversion costs			4,748,400	38.86
Total direct costs			4,943,300	40.46
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,759,000	22.58
Average cost of capital and taxes at 8.6% of total capital investment			4,027,900	32.97
Overheads				
Plant, 50% of conversion cost less utilities			989,900	8.10
Administrative, 10% of operating labor			50,000	0.41
Marketing, 10% of byproduct sales revenue			61,300	0.50
Total indirect costs			7,888,100	64.56
Gross annual revenue requirements			12,831,400	105.02
Byproduct Sales Revenue				
100% sulfuric acid	22,840 tons	25.00/ton	(571,000)	(4.67)
Sodium sulfate	1,830 tons	23.00/ton	(42,100)	(0.35)
Net annual revenue requirements			12,218,300	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	4.07	8.60	0.45	1,531

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 6,000 hr/yr.
- Coal burned, 1,289,200 metric tons/yr (1,421,100 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
- Stack gas reheat to 79°C (175°F).
- Sulfur removed, 7,240 metric tons/yr (7,980 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $24,301,000; total depreciable investment, $45,983,000; and total capital investment, $46,836,000.
- All tons shown are 2,000 lb.

TABLE H-10. WELLMAN-LORD PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 1.4% S in coal;
90% SO_2 removal; sulfuric acid production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	261,000	1.0
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,827,000	18.4
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,558,000	17.4
Stack gas reheat (four indirect steam reheaters)	1,212,000	4.6
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,860,000	18.5
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	1,458,000	5.5
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	3,958,000	15.1
Acid production (complete contact unit for sulfuric acid production)	2,928,000	11.2
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	476,000	1.8
Subtotal	24,538,000	93.5
Services, utilities, and miscellaneous	1,472,000	5.6
Total excluding pond	26,010,000	99.1
Pond	234,000	0.9
Total direct investment	26,244,000	100.0
Indirect Investment		
Engineering design and supervision	2,053,000	7.8
Architect and engineering contractor	509,000	1.9
Construction expense	3,776,000	14.4
Contractor fees	1,150,000	4.4
Total indirect investment	7,488,000	28.5
Contingency	6,746,000	25.7
Total fixed investment	40,478,000	154.2
Other Capital Charges		
Allowance for startup and modifications	4,024,000	15.3
Interest during construction	4,857,000	18.6
Total depreciable investment	49,359,000	188.1
Land	28,000	0.1
Working capital	920,000	3.5
Total capital investment	50,307,000	191.7

Basis
- Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
- Stack gas reheat to 79°C (175°F) by indirect steam reheat.
- Minimum in-process storage; only pumps are spared.
- Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
- Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE H-11. WELLMAN-LORD PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 1.4% S in coal;
90% SO_2 removal; sulfuric acid production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	2,135 tons	103.00/ton	219,900	1.68
Catalyst	610 liters	2.50/liter	1,500	0.01
Agricultural limestone	5,505 tons	15.00/ton	82,600	0.63
Filter aid	25 tons	189.00/ton	4,700	0.04
Total raw material cost			308,700	2.36
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	3.82
Utilities				
Steam	741,500 MBtu	2.00/MBtu	1,483,000	11.35
Process water	1,823,700 kgal	0.12/kgal	218,800	1.67
Electricity	49,414,800 kWh	0.029/kWh	1,433,000	10.95
Heat credit	16,400 MBtu	2.00/MBtu	(32,800)	(0.25)
Maintenance				
Labor and material			1,567,600	11.98
Analyses	1,970 man-hr	17.00/man-hr	33,500	0.26
Total conversion costs			5,203,100	39.78
Total direct costs			5,511,800	42.14
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,961,500	22.64
Average cost of capital and taxes at 8.6% of total capital investment			4,326,400	33.07
Overheads				
Plant, 50% of conversion cost less utilities			1,050,600	8.03
Administrative, 10% of operating labor			50,000	0.38
Marketing, 10% of byproduct sales revenue			91,000	0.70
Total indirect costs			8,479,500	64.82
Gross annual revenue requirements			13,991,300	106.96
Byproduct Sales Revenue				
100% sulfuric acid	33,920 tons	25.00/ton	(848,000)	(6.48)
Sodium sulfate	2,710 tons	23.00/ton	(62,300)	(0.48)
Net annual revenue requirements			13,081,000	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	4.36	12.21	0.48	1,104

Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 972,200 metric tons/yr (1,071,600 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 10,750 metric tons/yr (11,850 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $26,244,000; total depreciable investment, $49,359,000; and total capital investment, $50,307,000.
All tons shown are 2,000 lb.

TABLE H-12. WELLMAN-LORD PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 2.0% S in coal;
90% SO_2 removal; sulfuric acid production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	348,000	1.2
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,842,000	16.1
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,577,000	15.3
Stack gas reheat (four indirect steam reheaters)	1,216,000	4.1
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,874,000	16.2
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	1,980,000	6.6
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	5,468,000	18.2
Acid production (complete contact unit for sulfuric acid production)	4,045,000	13.5
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	652,000	2.2
Subtotal	28,002,000	93.4
Services, utilities, and miscellaneous	1,680,000	5.6
Total excluding pond	29,682,000	99.0
Pond	300,000	1.0
Total direct investment	29,982,000	100.0
Indirect Investment		
Engineering design and supervision	2,137,000	7.1
Architect and engineering contractor	529,000	1.8
Construction expense	4,218,000	14.1
Contractor fees	1,273,000	4.2
Total indirect investment	8,157,000	27.2
Contingency	7,628,000	25.4
Total fixed investment	45,767,000	152.6
Other Capital Charges		
Allowance for startup and modifications	4,547,000	15.2
Interest during construction	5,492,000	18.3
Total depreciable investment	55,806,000	186.1
Land	28,000	0.1
Working capital	1,105,000	3.7
Total capital investment	56,939,000	189.9

Basis
- Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
- Stack gas reheat to 79°C (175°F) by indirect steam reheat.
- Minimum in-process storage; only pumps are spared.
- Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
- Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE H-13. WELLMAN-LORD PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 2.0% S in coal;
90% SO_2 removal; sulfuric acid production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	3,385 tons	103.00/ton	348,700	2.35
Catalyst	970 liters	2.50/liter	2,400	0.02
Agricultural limestone	8,295 tons	15.00/ton	124,400	0.84
Filter aid	40 tons	189.00/ton	7,600	0.05
Total raw material cost			483,100	3.26
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	3.38
Utilities				
Steam	969,100 MBtu	2.00/MBtu	1,938,200	13.09
Process water	2,798,800 kgal	0.12/kgal	335,900	2.27
Electricity	55,288,400 kWh	0.029/kWh	1,603,400	10.83
Heat credit	26,000 MBtu	2.00/MBtu	(52,000)	(0.35)
Maintenance				
Labor and material			1,787,900	12.08
Analyses	2,600 man-hr	17.00/man-hr	44,200	0.30
Total conversion costs			6,157,600	41.60
Total direct costs			6,640,700	44.86
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,348,400	22.62
Average cost of capital and taxes at 8.6% of total capital investment			4,896,800	33.08
Overheads				
Plant, 50% of conversion cost less utilities			1,166,100	7.88
Administrative, 10% of operating labor			50,000	0.34
Marketing, 10% of byproduct sales revenue			144,400	0.98
Total indirect costs			9,605,700	64.90
Gross annual revenue requirements			16,246,400	109.76
Byproduct Sales Revenue				
100% sulfuric acid	53,810 tons	25.00/ton	(1,345,300)	(9.09)
Sodium sulfate	4,300 tons	23.00/ton	(98,900)	(0.67)
Net annual revenue requirements			14,802,200	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	4.93	12.06	0.55	788

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 6,000 hr/yr.
- Coal burned, 1,113,400 metric tons/yr (1,227,300 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
- Stack gas reheat to 79°C (175°F).
- Sulfur removed, 17,050 metric tons/yr (18,790 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $29,982,000; total depreciable investment, $55,806,000; and total capital investment, $56,939,000.
- All tons shown are 2,000 lb.

TABLE H-14. WELLMAN-LORD PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new lignite-fired power unit, 0.5% S in lignite;
90% SO_2 removal; sulfuric acid production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	168,000	0.7
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	5,026,000	21.7
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,797,000	20.7
Stack gas reheat (four indirect steam reheaters)	1,267,000	5.5
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	5,080,000	21.9
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	912,000	3.9
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	2,406,000	10.4
Acid production (complete contact unit for sulfuric acid production)	1,780,000	7.7
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	293,000	1.3
Subtotal	21,729,000	93.8
Services, utilities, and miscellaneous	1,304,000	5.6
Total excluding pond	23,033,000	99.4
Pond	149,000	0.6
Total direct investment	23,182,000	100.0
Indirect Investment		
Engineering design and supervision	1,965,000	8.5
Architect and engineering contractor	488,000	2.1
Construction expense	3,405,000	14.7
Contractor fees	1,047,000	4.5
Total indirect investment	6,905,000	29.8
Contingency	6,017,000	26.0
Total fixed investment	36,104,000	155.8
Other Capital Charges		
Allowance for startup and modifications	3,596,000	15.5
Interest during construction	4,333,000	18.7
Total depreciable investment	44,033,000	190.0
Land	28,000	0.1
Working capital	776,000	3.3
Total capital investment	44,837,000	193.4

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 79°C (175°F) by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE H-15. WELLMAN-LORD PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW lignite-fired power unit, 0.5% S in lignite;
90% SO_2 removal; sulfuric acid production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	1,050 tons	103.00/ton	108,200	0.92
Catalyst	300 liters	2.50/liter	800	0.01
Agricultural limestone	2,630 tons	15.00/ton	39,500	0.34
Filter aid	10 tons	189.00/ton	1,900	0.02
Total raw material cost			150,400	1.29
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	4.25
Utilities				
Steam	567,000 MBtu	2.00/MBtu	1,134,000	9.65
Process water	986,700 kgal	0.12/kgal	118,400	1.01
Electricity	46,872,000 kWh	0.029/kWh	1,359,300	11.56
Heat credit	8,000 MBtu	2.00/MBtu	(16,000)	(0.14)
Maintenance				
Labor and material			1,386,500	11.80
Analyses	1,285 man-hr	17.00/man-hr	21,800	0.18
Total conversion costs			4,504,000	38.31
Total direct costs			4,654,400	39.60
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,642,000	22.47
Average cost of capital and taxes at 8.6% of total capital investment			3,856,000	32.80
Overheads				
Plant, 50% of conversion cost less utilities			954,200	8.12
Administrative, 10% of operating labor			50,000	0.43
Marketing, 10% of byproduct sales revenue			44,700	0.38
Total indirect costs			7,546,900	64.20
Gross annual revenue requirements			12,201,300	103.80
Byproduct Sales Revenue				
100% sulfuric acid	16,640 tons	25.00/ton	(416,000)	(3.54)
Sodium sulfate	1,330 tons	23.00/ton	(30,600)	(0.26)
Net annual revenue requirements			11,754,700	100.00

	Mills/kWh	$/ton lignite burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	3.92	6.88	0.44	2,023

Basis
Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Lignite burned, 1,550,200 metric tons/yr (1,708,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Stack gas reheat to 79°C (175°F).
Sulfur removed, 5,270 metric tons/yr (5,810 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $23,182,000; total depreciable investment, $44,033,000; and total capital investment, $44,837,000.
All tons shown are 2,000 lb.

TABLE H-16. WELLMAN-LORD PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new oil-fired power unit, 2.5% S in oil;
90% SO_2 removal; sulfuric acid production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	315,000	1.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,292,000	18.9
SO_2 absorption (four absorbers, presaturators, and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,888,000	21.5
Stack gas reheat (four direct oil-fired reheaters)	1,065,000	4.7
Chloride purge	-	-
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	1,781,000	7.8
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	4,887,000	21.5
Acid production (complete contact unit for sulfuric acid production)	3,615,000	15.9
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	585,000	2.6
Subtotal	21,428,000	94.3
Services, utilities, and miscellaneous	1,286,000	5.7
Total direct investment	22,714,000	100.0
Indirect Investment		
Engineering design and supervision	1,981,000	8.7
Architect and engineering contractor	495,000	2.2
Construction expense	3,339,000	14.8
Contractor fees	1,031,000	4.5
Total indirect investment	6,846,000	30.2
Contingency	5,912,000	26.0
Total fixed investment	35,472,000	156.2
Other Capital Charges		
Allowance for startup and modifications	3,547,000	15.6
Interest during construction	4,257,000	18.7
Total depreciable investment	43,276,000	190.5
Land	28,000	0.1
Working capital	911,000	4.0
Total capital investment	44,215,000	194.6

Basis
Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 79°C (175°F) by direct oil-fired reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE H-17. WELLMAN-LORD PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new oil-fired power unit, 2.5% S in oil;
90% SO_2 removal; sulfuric acid production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	2,890 tons	103.00/ton	297,700	2.52
Catalyst	830 liters	2.50/liter	2,100	0.02
Agricultural limestone	0 tons	15.00/ton	-	-
Filter aid	35 tons	189.00/ton	6,600	0.06
Total raw material cost			306,400	2.60
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	4.24
Utilities				
Fuel oil (No. 6)	2,078,500 gal	0.40/gal	831,400	7.04
Steam	521,300 MBtu	2.00/MBtu	1,042,600	8.83
Process water	2,383,600 kgal	0.12/kgal	286,000	2.42
Electricity	40,842,900 kWh	0.029/kWh	1,184,400	10.04
Heat credit	22,200 MBtu	2.00/MBtu	(44,400)	(0.38)
Maintenance				
Labor and material			1,362,800	11.55
Analyses	2,365 man-hr	17.00/man-hr	40,200	0.34
Total conversion costs			5,203,000	44.08
Total direct costs			5,509,400	46.68
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,596,600	22.00
Average cost of capital and taxes at 8.6% of total capital investment			3,802,500	32.23
Overheads				
Plant, 50% of conversion cost less utilities			951,500	8.06
Administrative, 10% of operating labor			50,000	0.42
Marketing, 10% of byproduct sales revenue			123,100	1.04
Total indirect costs			7,523,700	63.75
Gross annual revenue requirements			13,033,100	110.43
Byproduct Sales Revenue				
100% sulfuric acid	45,870 tons	25.00/ton	(1,146,800)	(9.72)
Sodium sulfate	3,670 tons	23.00/ton	(84,400)	(0.71)
Net annual revenue requirements			11,801,900	100.00

	Mills/kWh	$/bbl oil burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	3.93	2.64	0.44	737

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 6,000 hr/yr.
- Oil burned, 710 x 10^6 liters/yr (4,464,300 bbl/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
- Stack gas reheat to 79°C (175°F).
- Sulfur removed, 14,530 metric tons/yr (16,020 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $22,714,000; total depreciable investment, $43,276,000; and total capital investment, $44,215,000.
- All tons shown are 2,000 lb.

TABLE H-18. WELLMAN-LORD PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; sulfur production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	503,000	1.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,861,000	12.9
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,595,000	12.1
Stack gas reheat (four indirect steam reheaters)	1,221,000	3.2
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,894,000	12.9
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	2,934,000	7.7
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	8,297,000	21.9
SO_2 reduction (complete reduction unit)	7,600,000	20.1
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	710,000	1.9
Subtotal	35,615,000	94.0
Services, utilities, and miscellaneous	2,137,000	5.6
Total excluding pond	37,752,000	99.6
Pond	154,000	0.4
Total direct investment	37,906,000	100.0
Indirect Investment		
Engineering design and supervision	2,373,000	6.3
Architect and engineering contractor	590,000	1.5
Construction expense	5,118,000	13.5
Contractor fees	1,521,000	4.0
Total indirect investment	9,602,000	25.3
Contingency	9,502,000	25.1
Total fixed investment	57,010,000	150.4
Other Capital Charges		
Allowance for startup and modifications	5,686,000	15.0
Interest during construction	6,841,000	18.0
Total depreciable investment	69,537,000	183.4
Land	28,000	0.1
Working capital	1,777,000	4.7
Total capital investment	71,342,000	188.2

Basis
- Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
- Stack gas reheat to 79°C (175°F) by indirect steam reheat.
- Minimum in-process storage; only pumps are spared.
- Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
- Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE H-19. WELLMAN-LORD PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new coal-fired power unit, 3.5% S in coal;
90% SO_2 removal; sulfur production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	6,150 tons	103.00/ton	633,500	3.01
Agricultural limestone	2,780 tons	15.00/ton	41,700	0.20
Filter aid	70 tons	189.00/ton	13,200	0.06
Natural gas	489,600 kft^3	3.50/kft^3	1,713,600	8.16
Catalyst			16,700	0.08
Total raw material cost			2,418,700	11.51
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	2.38
Utilities				
Steam	1,483,200 MBtu	2.00/MBtu	2,966,400	14.11
Process water	4,190,400 kgal	0.12/kgal	502,800	2.39
Electricity	67,690,100 kWh	0.029/kWh	1,963,000	9.34
Heat credit	66,400 MBtu	2.00/MBtu	(132,800)	(0.63)
Maintenance				
Labor and material			2,269,700	10.80
Analyses	3,720 man-hr	17.50/man-hr	65,100	0.31
Total conversion costs			8,134,200	38.70
Total direct costs			10,552,900	50.21
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,172,200	19.85
Average cost of capital and taxes at 8.6% of total capital investment			6,135,400	29.20
Overheads				
Plant, 50% of conversion cost less utilities			1,417,400	6.74
Administrative, 10% of operating labor			50,000	0.24
Marketing, 10% of byproduct sales revenue			145,800	0.69
Total indirect costs			11,920,800	56.72
Gross annual revenue requirements			22,473,700	106.93
Byproduct Sales Revenue				
Sulfur	31,960 tons	40.00/ton	(1,278,400)	(6.08)
Sodium sulfate	7,810 tons	23.00/ton	(179,600)	(0.85)
Net annual revenue requirements			21,015,700	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	7.00	16.34	0.78	616

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 6,000 hr/yr.
- Coal burned, 1,166,200 metric tons/yr (1,285,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
- Stack gas reheat to 79°C (175°F).
- Sulfur removed, 30,950 metric tons/yr (34,120 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $37,906,000; total depreciable investment, $69,537,000; and total capital investment, $71,342,000.
- All tons shown are 2,000 lb.

APPENDIX I

CARBON ADSORPTION PROCESS

PROCESS DESCRIPTION

The Bergbau-Forschung/Foster Wheeler process uses dry carbon adsorption followed by thermal regeneration to reactivate the adsorbent. A four-train adsorption system, each with a two-stage absorber, is used. The adsorber stages are separate but adjacent vessels, each containing louvered moving beds of activated char. The flow diagram is shown in Figure I-1. The material balance is shown in Table I-1 and the equipment list is shown in Table I-2.

Water is mixed with the hot flue gas to obtain an adsorber inlet temperature of 121°C (250°F). The gas then moves in horizontal crossflow through a vertical char bed where SO_2, SO_3, H_2O, and O_2 are adsorbed. Although some NO_x removal has also been reported the process is not designed for NO_x removal. The char bed also filters out some residual fly ash in the flue gas. The flue gas leaving the first stage is divided into upper and lower flow streams. The upper stream flows to the first-stage adsorber ID fan and then to the stack plenum. The lower stream flows to the second-stage adsorber and then to a separate ID fan. Because of exothermic reactions the gases are exhausted about 14°C above the adsorber inlet temperature. Hence, there is no need for reheat.

The char moves by gravity in the adsorber beds. The velocity ranges from 0.3 to 0.91 m/hr (1 to 3 ft/hr). Char leaving the adsorbers is saturated with H_2SO_4 formed by reaction between SO_2, O_2, and H_2O. The saturated char is screened to remove fly ash and char fines and transported to the regeneration area. Saturated char and hot sand are gravity-fed into the regenerator vessel which operates with a reducing atmosphere. Sand enters the regenerator at 815°C (1500°F) and char enters at the flue gas temperature. The saturated char is heated to 650°C (1200°F) to liberate the adsorbed gases and return the char to its activated state. Some char reacts with oxygen in the gas and is chemically consumed. Sand and regenerated char leave the regenerator at 650°C (1200°F) and are separated by screens. The char is then routed to the char cooling area and the sand is heated and returned to the regenerator.

In the char cooling area, the char is cooled in two stages. First-stage cooling by indirect heat exchange with cleaned flue gas lowers char temperature to 200°C. The temperature is reduced to 120°C in the second stage by direct-contact water spray. The steam produced is unsuitable for use by the steam plant. It can, however, be used to preheat boiler feedwater. Makeup char is added to replace losses. The char is then transported back to the top of the adsorbers. The sand is simultaneously heated and pneumatically elevated to the regenerator by combustion gases. The heater gas may be routed either to the stack or to the adsorbers, depending on whether or not it contains SO_2.

SO_2 reduction is accomplished by the Foster Wheeler RESOX^{TM} process. The SO_2-rich gas is reacted with rice-sized anthracite coal to produce gaseous elemental sulfur. SO_2 and air are injected at the bottom of a RESOX reactor containing downward moving coal. The operating temperature is 800-850°C in the main reaction zone. In addition to sulfur vapor, some H_2S, COS, and CS_2 are formed in the reactor. The product gases, flowing out the top of the reactor at 350-400°C, are routed to a shell and tube exchanger to condense the sulfur product and produce steam. Recovered sulfur is then collected and pumped to storage. Noncondensed gases from the sulfur condenser are pumped to an incinerator to oxidize the remaining sulfur compounds back to SO_2. After incineration, the gases are cooled in a steam-producing waste heat boiler and recycled back to the SO_2 adsorbers.

SPECIFIC PROCESS PREMISES

1. The adsorbers have superficial velocities of 7.6 m/sec (25 ft/sec) in channels between the char beds and 0.3 m/sec (1 ft/sec) approaching the char beds. Pressure drop is 0.5 kPa (2.0 inches H_2O) in the first stage and 0.3 kPa (1 inch H_2O) in the second stage.

2. The saturated char SO_2 loading is 7.5 kg of sulfur to 100 kg of char.

ENERGY REQUIREMENTS

For base-case conditions, steam consumption in the SO_2 reduction and sulfur storage area totals 1,300 kg/hr (2,860 lb/hr) of 148°C (298°F) steam at 450 kPa absolute pressure (50.3 psig) equivalent to about 0.66 x 10^6 kcal/hr. In addition to the steam consumed in this area, steam is produced in some areas. This, along with heat used to preheat boiler feedwater, is taken into account as a heat credit. The waste heat boiler produces 4,600 kg/hr (10,100 lb/hr) of 121°C (250°F) steam at 210 kPa absolute pressure (15.1 psig) equivalent to about 2.79 x 10^6 kcal/hr. The sulfur production unit produces 17,400 kg/hr (38,300 lb/hr) of 121°C (250°F) steam at 210 kPa absolute pressure (15.1 psig) equivalent to about 10.58 x 10^6 kcal/hr. The waste heat from the char cooler is used to preheat boiler feedwater from 38°C (100°F) to 88°C (190°F). This is equivalent to about 1.45 x 10^6 kcal/hr.

The electrical power demand for the base-case carbon adsorption process is about 2,650 kW or 0.53% of the rated capacity of a 500-MW power plant. For 6,000 hours of operation, the annual electrical energy consumption is 15.92 x 10^6 kWh.

Fuel oil is used as a source of energy at an annual rate of 15.48×10^6 liters (4.09×10^6 gal), equivalent to about 22.54×10^6 kcal/hr, to heat sand. For SO_2 reduction the annual consumption is 3.12×10^6 liters (0.82×10^6 gal). The total fuel oil consumption for energy is equivalent to 27.10×10^6 kcal/hr. There is no reheat steam required for this process.

The total equivalent energy consumption for the base case is approximately 19.02×10^6 kcal/hr or 1.68% of the input energy required for the 500-MW power unit. Summarized energy requirements for all cases are listed in Table I-3.

BYPRODUCT MANAGEMENT

ESP units remove 99.2% of the fly ash from the flue gas; some additional fly ash is removed with the char fines. The char fines and RESOX waste may be burned in the boiler. These two materials have been assigned a monetary value based on their heating values and are treated as salable byproducts in the determination of net annual revenue requirements. (Fly ash emission from oil-fired units does not exceed the EPA particulate emission standard and fly ash collection facilities are not included in oil-fired power plant design.) Projected mass flow rates of byproduct streams are shown below.

	Component	Kg/hr	Lb/hr
Sulfur:	Sulfur	4,900	10,900
Other:	Char fines	1,660	3,660
	Fly ash	150	330
	RESOX waste	2,600	5,700
		4,410	9,690

ECONOMIC EVALUATION

Capital investment and annual revenue requirement summaries for the base case and five fuel variations are shown in Tables I-4 and I-5. The detailed results are shown in Tables I-6 through I-19. The same results showing the range of estimated accuracies are shown graphically in Figures I-2 and I-3. The effect of fuel sulfur content on costs is shown in Figure I-4.

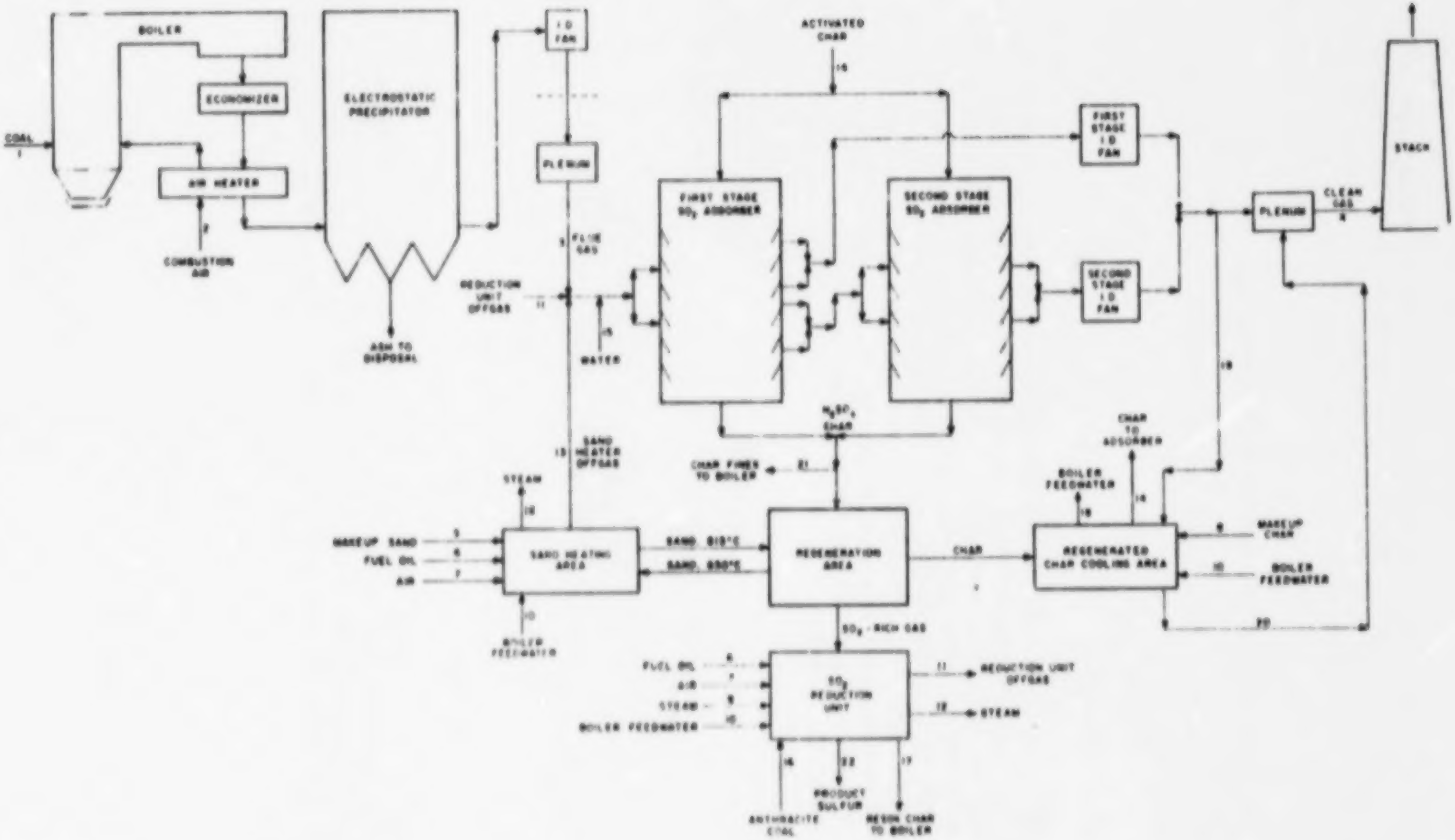
COAL
1
BOILER
ECONOMIZER
AIR HEATER
2
COMBUSTION AIR
ELECTROSTATIC PRECIPITATOR
ASH TO DISPOSAL
I D FAN
PLENUM
3 FLUE GAS
REDUCTION UNIT OFFGAS
11
15
WATER
13 SAND HEATER OFFGAS
STEAM
12
MAKEUP SAND
5
FUEL OIL
6
AIR
7
SAND HEATING AREA
10
BOILER FEEDWATER
ACTIVATED CHAR
16
FIRST STAGE SO_2 ADSORBER
SECOND STAGE SO_2 ADSORBER
FIRST STAGE I D FAN
SECOND STAGE I D FAN
H_2SO_4 CHAR
CHAR FINES TO BOILER
21
SAND, 815°C
SAND, 650°C
REGENERATION AREA
CHAR
SO_2 - RICH GAS
FUEL OIL
6
AIR
7
STEAM
9
BOILER FEEDWATER
10
SO_2 REDUCTION UNIT
11
REDUCTION UNIT OFFGAS
12
STEAM
16
ANTHRACITE COAL
22
PRODUCT SULFUR
17
RESID CHAR TO BOILER
BOILER FEEDWATER
18
CHAR TO ADSORBER
14
REGENERATED CHAR COOLING AREA
8
MAKEUP CHAR
10
BOILER FEEDWATER
19
20
PLENUM
CLEAN GAS
4
STACK

Figure I-1. Carbon adsorption process flow diagram.

TABLE I-1. CARBON ADSORPTION PROCESS

MATERIAL BALANCE - BASE CASE (3.5% SULFUR COAL)

	Stream No.	1	2	3	4	5
	Description	Coal to boiler	Combustion air to air heater	Flue gas to adsorber	Gas to stack	Makeup sand
1	Total stream, 1000 kg/hr	194	2,062	2,225	2,311	0.45
2	Total stream, lb/hr	428,600	4,546,200	4,906,000	5,094,500	1,000
3	Gas flow, Nm^3/hr (0°C)		1,615,700	1,697,700	1,782,400	
4	Gas flow, sft^3/min (60°F		1,005,000	1,056,000	1,106,200	
5	Temperature, °C		27	149	153	
6	Particulates, kg/hr			200	50	
7	Particulates, lb/hr			439	110	
8						
9						
10						

	Stream No.	6	7	8	9	10
	Description	Fuel oil	Process air	Makeup char	Process steam	Boiler feedwater
1	Total stream, 1000 kg/hr	2.7	55.0	2.4	1.3	22.0
2	Total stream, lb/hr	5,980	121,200	5,210	2,860	48,400
3	Gas flow, Nm^3/hr (0°C)		42,500			
4	Gas flow, sft^3/min (60°F		26,400			
5	Liquid flow, liters/min	50				370
6	Liquid flow, gal/min	13				100
7	Temperature, °C		27		148	38
8	Pressure, kPa (abs)				0.45 x 10^3	
9	Pressure, psig				50.3	
10						

	Stream No.	11	12	13	14	15
	Description	RESOX off-gas	Steam to steam plant	Sand heater off-gas	Char to adsorber	Flue gas cooling water
1	Total stream, 1000 kg/hr	38.3	22.0	41.9	74.6	25.5
2	Total stream, lb/hr	84,400	48,400	92,300	164,600	56,300
3	Gas flow, Nm^3/hr (0°C)	32,700		32,600		
4	Gas flow, sft^3/min (60°F)	20,300		20,200		
5	Liquid flow, liters/min					426
6	Liquid flow, gal/min					113
7	Temperature, °C	149	121	816	121	27
8	Pressure, kPa (abs)		0.2 x 10^3			
9	Pressure, psig		15.1			
10						

	Stream No.	16	17	18	19	20
	Description	Anthracite coal to RESOX	RESOX waste coal to boiler	Boiler feedwater from char cooler	Flue gas to char cooler	Flue gas from char cooler
1	Total stream, 1000 kg/hr	5.0	2.6	28.9	171.8	171.8
2	Total stream, lb/hr	11,100	5,700	63,800	378,800	378,800
3	Liquid flow, liters/min			482		
4	Liquid flow, gal/min			127		
5	Temperature, °C			88	135	371
6	Undissolved solids, %					
7	Gas flow, Nm^3/hr (0°C)				132,400	132,400
8	Gas flow, sft^3/min (60°F)				82,300	82,300
9	Specific gravity					
10						

(continued)

TABLE I-1. (continued)

	Stream No.	21	22			
	Description	Char fines to boiler	Product sulfur			
1	Total stream, 1000 kg/hr	1.8	4.9			
2	Total stream, lb/hr	3,990	10,900			
3	Gas flow, Nm^3/hr (0°C)					
4	Gas flow, sft^3/min (60°F)					
5	Liquid flow, liters/min		46			
6	Liquid flow, gal/min		12			
7	Temperature, °C	135	138			
8	Pressure, kPa					
9	Pressure, psig					
10						

1						
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7						
8						
9						
10						

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2						
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7						
8						
9						
10						

TABLE I-2. CARBON ADSORPTION PROCESS

BASE-CASE EQUIPMENT LIST DESCRIPTION AND COST

Area 1--Materials Handling			Area size-cost exponent 0.63	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Car shaker	1	Top mounting with crane	9,000	2,100
2. Car puller	1	25 hp with 5 hp return	50,000	2,100
3. Hopper, unloading	1	12 ft x 20 ft x 2 ft bottom, 20 ft deep, 4,800 ft^3, carbon steel	9,300	8,700
4. Feeder, unloading	1	Vibrating pan, 36 in. wide x 60 in. long, 2 hp, 120 tons/hr	4,800	1,100
5. Conveyor, unloading	1	Belt, 30 in. wide x 10 ft long, 1 hp, 120 tons/hr, 200 ft/min	2,000	1,000
6. Conveyor, stocking (inclined, enclosed)	1	Belt, 30 in. wide x 200 ft long, 15 hp, 15° slope, 120 tons/hr, 200 ft/min	27,000	10,000
7. Conveyor, char stocking (enclosed)	1	Belt, 30 in. wide x 40 ft long, 1-1/2 hp, 120 tons/hr, 200 ft/min	9,100	4,400
8. Elevator, char storage	1	Continuous, bucket 16 in. x 12-5/8 in. x 17-5/8 in., 30 hp, 85 ft lift, 120 tons/hr, 100 ft/min, with diverter gate	44,900	2,000

(continued)

TABLE I-2. (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
9. Silo, char storage	2	40 ft dia x 40 ft straight side, 50,300 ft^3, 60° slope, 3/8 in. carbon steel	105,500	241,600
10. Feeder, reclaim	2	Vibrating pan, 3 tons/hr	14,000	4,200
11. Conveyor, live char (inclined, enclosed)	1	Belt, 14 in. wide x 200 ft long, 1-1/2 hp, 11° slope, 3 tons/hr, 25 ft/min	34,600	11,000
12. Conveyor, sand	1	Pneumatic, pressure, 125 hp	100,000	20,000
13. Bin, sand storage	1	18-1/2 ft dia x 27 ft straight side, w/cover	13,300	23,200
14. Feeder, reclaim	1	Vibrating pan, 1,000 lb/hr	7,000	2,100
15. Tank, fuel oil	1	46-1/2 ft dia x 46-1/2 ft high, 590,800 gal, covered top, carbon steel	53,300	99,200
16. Pump, fuel oil	2	Centrifugal, 14 gpm, 200 ft head, 2 hp, carbon steel (1 operating, 1 spare)	3,500	1,300
Subtotal			487,300	434,000

(continued)

TABLE I-2. (continued)

Area 2--Feed Preparation	Area size-cost exponent
Note: No equipment in this area.	

Area 3--Gas Handling			Area size-cost exponent 0.68	
Item	**No.**	**Description**	**Total material cost, 1979 $**	**Total labor cost, 1979 $**
1. Fan, first-stage adsorber	2	Induced draft, 4 in. static head, 890 rpm, 400 hp, fluid drive, double width, double inlet	366,000	30,000
2. Fan, second-stage adsorber	2	Induced draft, 5 in. static head, 890 rpm, 450 hp, fluid drive, double width, double inlet	370,000	30,000
Subtotal			736,000	60,000

Area 4--SO_2 Adsorption			Area size-cost exponent 0.79	
Item	**No.**	**Description**	**Total material cost, 1979 $**	**Total labor cost, 1979 $**
1. Adsorders, first stage	4	Moving-bed adsorber, 58 ft long x 28 ft wide x 84 ft high, 1/4 in. carbon steel shell, louvered beds, 5/8 in. carbon steel louvers, carbon adsorbent	5,026,000	401,000
2. Adsorbers, second stage	4	Moving-bed adsorber, 58 ft long x 28 ft wide x 54 ft high, 1/4 in. carbon steel shell, louvered beds, 5/8 in. carbon steel louvers, carbon adsorbent	2,933,500	300,600

(continued)

TABLE I-2. (continued)

	Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
3.	Feeder, adsorber discharge	144	Weigh, vibratory, 10 in. wide x 36 in. long, 1,420 lb/hr	172,800	86,400
4.	Conveyor, adsorber discharge (enclosed)	8	Oscillating, 120 ft long, 4 in. deep x 20 in. wide trough, 10 hp, 13 tons/hr, 20 ft/min, carbon steel	202,400	60,700
5.	Screens	4	36 in. wide x 96 in. long, carbon steel	31,100	2,200
6.	Conveyor, char collection (enclosed)	1	Pivoted buckets, 30 in. x 24 in, 20 hp, 200 ft long, 100 tons/hr, 100 ft/min	104,600	31,400
7.	Conveyor, char surge bin feed (enclosed)	1	Pivoted buckets, 30 in. x 24 in., 15 hp, 130 ft long, 100 tons/hr, 100 ft/min	68,000	20,400
8.	Conveyor-elevator char surge bin	1	Pivoted buckets, 30 in. x 24 in., 25 hp, 35 ft long, 130 ft lift, 100 tons/hr, 100 ft/min, with diverter gate	96,300	25,900
9.	Hopper, char fines/fly ash collection	4	36 in. wide x 96 in. long, 5 ft deep, 1/2 ft bottom	1,500	2,900
10.	Conveyor, char fines/fly ash	1	Pneumatic, pressure, 40 hp	37,700	8,600
11.	Bin, char feed	8	18 ft dia x 24 ft straight side, w/cover, carbon steel	84,600	151,300
	Insulation			44,200	44,200

TABLE I-2. (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
12. Pump, flue gas cooling water	2	Centrifugal, 110 gpm, 150 ft head, 15 hp, carbon steel (1 operating, 1 spare)	8,200	1,600
Subtotal			8,810,900	1,137,200

Area 5--Reheat

Area size-cost exponent 0.65

Note: No equipment in this area.

Area 6--Regeneration

Area size-cost exponent 0.65

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Bin, saturated char surge	2	14 ft dia x 14 ft straight side, w/cover	11,400	19,600
Insulation			6,600	6,600
2. Feeder, surge bin discharge	2	Weigh, vibratory, 12 in. x 36 in. trough, 50 tons/hr, carbon steel	24,400	4,200
3. Regenerator	2	Moving bed, 13 ft inside dia x 26 ft straight side, carbon steel	23,500	40,500
Lining		12 in. firebrick, 8 in. insulation brick	151,900	20,400

(continued)

TABLE I-2. (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
4. Feeder, regenerator discharge	2	Weigh, vibratory, 42 in. x 60 in. trough, 270 tons/hr, 316 stainless steel	38,400	4,400
5. Separator, char/sand	2	8 ft wide x 24 ft long, 316 stainless steel	89,000	8,800
Subtotal			345,200	104,500

Area 7--Char Cooling

Area size-cost exponent 0.69

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Char cooler, primary	2	Tube type, 2,650 ft^2, 316 stainless steel tubes	143,000	122,800
2. Char cooler, secondary	2	Direct cooling spray chamber, 5 ft wide x 30 ft long x 5 ft high, carbon steel construction	6,300	12,000
Conveyor, char cooling	2	Oscillating, 25 ft long, 4 in. deep x 36 in. wide trough, 2 hp, 40 tons/hr, 50 ft/min, carbon steel	10,000	3,000
3. Heater, boiler feedwater	1	Plate and frame, 350 ft^2, 316 stainless steel	7,500	1,000

(continued)

TABLE I-2. (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
4. Pump, char cooling water circulation	2	Centrifugal, 12 gpm, 60 ft head, 1/2 hp, carbon steel, neoprene lined (1 operating, 1 spare)	3,300	1,200
5. Fan, flue gas diversion	1	Forced draft, 5 in. static head, 116,300 aft^3/min, 150 hp	84,900	7,000
6. Hopper, cooled char collection	1	5 ft wide x 20 ft long, 10 ft deep, w/cover, carbon steel	1,300	2,500
7. Feeder, char hopper discharge	1	Vibrating pan, 80 tons/hr	9,600	2,200
8. Conveyor, cooled char	1	Pivoted buckets, 30 in. x 24 in., 25 hp, 240 ft long, 80 tons/hr, 100 ft/min	110,400	33,100
9. Conveyor elevator, first-stage adsorber char	1	Pivoted buckets, 20 in. x 20 in., 25 hp, 200 ft long, 150 ft lift, 40 tons/hr, 100 ft/min	121,500	36,400
10. Conveyor-elevator, second-stage adsorber char	1	Pivoted buckets, 20 in. x 20 in., 20 hp, 200 ft long, 120 ft lift, 40 tons/hr, 100 ft/min	111,000	33,300
Subtotal			608,800	254,500

(continued)

TABLE I-2. (continued)

Area 8--Sand Heating			Area size-cost exponent 0.69	
Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Hopper, sand collection	2	10 ft wide x 20 ft long x 10 ft deep, carbon steel	8,400	16,000
Lining		12 in. firebrick, 8 in. insulation brick	25,000	7,000
2. Feeder, sand hopper discharge	2	Weigh, screw. 24 in. dia x 15 ft long, 40 hp, 230 tons/hr, 316 stainless steel	77,200	4,200
3. Heater/elevator, sand	2	Pneumatic, pressure, 28 in. inside dia, 100 ft lift, 230 tons/hr, carbon steel	33,800	64,400
Lining		12 in. firebrick, 8 in. insulation brick	111,000	14,900
4. Dust collector	2	Cyclone, 38,100 aft^3/min, carbon steel, refractory lined	131,200	6,000
5. Blower, air	2	Single-stage centrifugal, 9,630 sft^3/min, 400 hp, 316 stainless steel	299,600	3,000
6. Air preheater	2	Tube type, 7,600 ft^2, 316 stainless steel shell, tubes, and heads	235,200	235,200
7. Waste heat boiler	1	Tube type, 3,200 ft^3, 316 stainless steel tubes and heads	67,200	67,200
Subtotal			988,600	417,900

(continued)

TABLE I-2. (continued)

Area 9--SO_2 Reduction

Area size-cost exponent 0.80

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. SO_2 reduction unit	1	RESOX (TM), complete unit, battery limit	7,800,000	-
Subtotal			7,800,000	-

Area 10--Sulfur Storage and Shipping

Area size-cost exponent 0.68

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
1. Pit, sulfur receiving	1	10 ft wide x 10 ft long x 10 ft deep, w/cover, 304 stainless steel	3,600	6,800
Insulation			1,000	1,500
Heater	1	Steam, 100 ft^2, 400 ft of 1 in. schedule 40, 304 stainless steel	1,000	1,500
2. Pump, sulfur transfer	2	Centrifugal, 13 gpm, 100 ft head, 2 hp, 316 stainless steel, high temperature, steam traced and insulated (1 operating, 1 spare)	5,000	500
3. Tank, sulfur storage	1	45 ft dia x 46 ft high, 696,900 gal, w/cover, 304 stainless steel	83,700	275,000

(continued)

TABLE I-2. (continued)

Item	No.	Description	Total material cost, 1979 $	Total labor cost, 1979 $
3. continued				
Insulation			15,700	15,700
Heater	1	Steam, 300 ft^2, 1,200 ft of 1 in. schedule 40, 304 stainless steel	2,400	4,000
4. Pump, sulfur shipping	2	Centrifugal, submerged, 60 gpm, 100 ft head, 5 hp, 316 stainless steel, steam traced and insulated	6,500	600
Subtotal			118,900	305,600

TABLE I-3. CARBON ADSORPTION PROCESS ENERGY REQUIREMENTS

Case	Reheat, kcal/hr	Electricity, kcal/hr (kW)	Process steam, kcal/hr	Heat credit, kcal/hr	Fuel oil, kcal/hr	Total equivalent energy consumption,[a] % of input energy
500-MW unit						
Coal, 3.5% sulfur (base case)	-	6.01 M (2,650)	0.66 M	14.82 M	27.10 M	1.68
Coal, 0.8% sulfur	-	3.86 M (1,700)	0.15 M	3.46 M	6.33 M	0.61
Coal, 1.4% sulfur	-	4.08 M (1,800)	0.23 M	5.14 M	9.41 M	0.76
Coal, 2.0% sulfur	-	3.83 M (1,690)	0.36 M	8.16 M	14.92 M	0.97
Lignite, 0.5% sulfur	-	3.74 M (1,650)	0.11 M	2.52 M	4.61 M	0.52
Oil, 2.5% sulfur	-	3.99 M (1,760)	0.31 M	6.96 M	12.72 M	0.89

a. Based on a boiler efficiency of 90% for generation of steam and a gross heat rate of 9,000 Btu/kWh for generation of electricity.

TABLE I-4. CARBON ADSORPTION PROCESS CAPITAL INVESTMENT

Case	Total capital investment $	 $/kW
500-MW unit		
Coal, 3.5% sulfur (base case)	73,511,000	147
Coal, 0.6% sulfur	51,195,000	102
Coal, 1.4% sulfur	54,220,000	108
Coal, 2.0% sulfur	60,834,000	122
Lignite, 0.5% sulfur	49,485,000	99
Oil, 2.5% sulfur	53,730,000	107

TABLE I-5. CARBON ADSORPTION PROCESS ANNUAL REVENUE REQUIREMENTS

Case	$	Mills/kWh	$/ton coal (bbl oil) burned	$/MBtu heat input	$/ton sulfur removed
500-MW unit					
Coal, 3.5% sulfur (base case)	28,489,400	9.50	22.16	1.06	835
Coal, 0.8% sulfur	13,899,100	4.63	9.78	0.51	1,742
Coal, 1.4% sulfur	15,803,600	5.27	14.75	0.59	1,334
Coal, 2.0% sulfur	19,982,700	6.66	16.28	0.74	1,063
Lignite, 0.5% sulfur	12,780,100	4.26	7.48	0.47	2,200
Oil, 2.5% sulfur	17,542,200	5.85	3.93	0.65	1,095

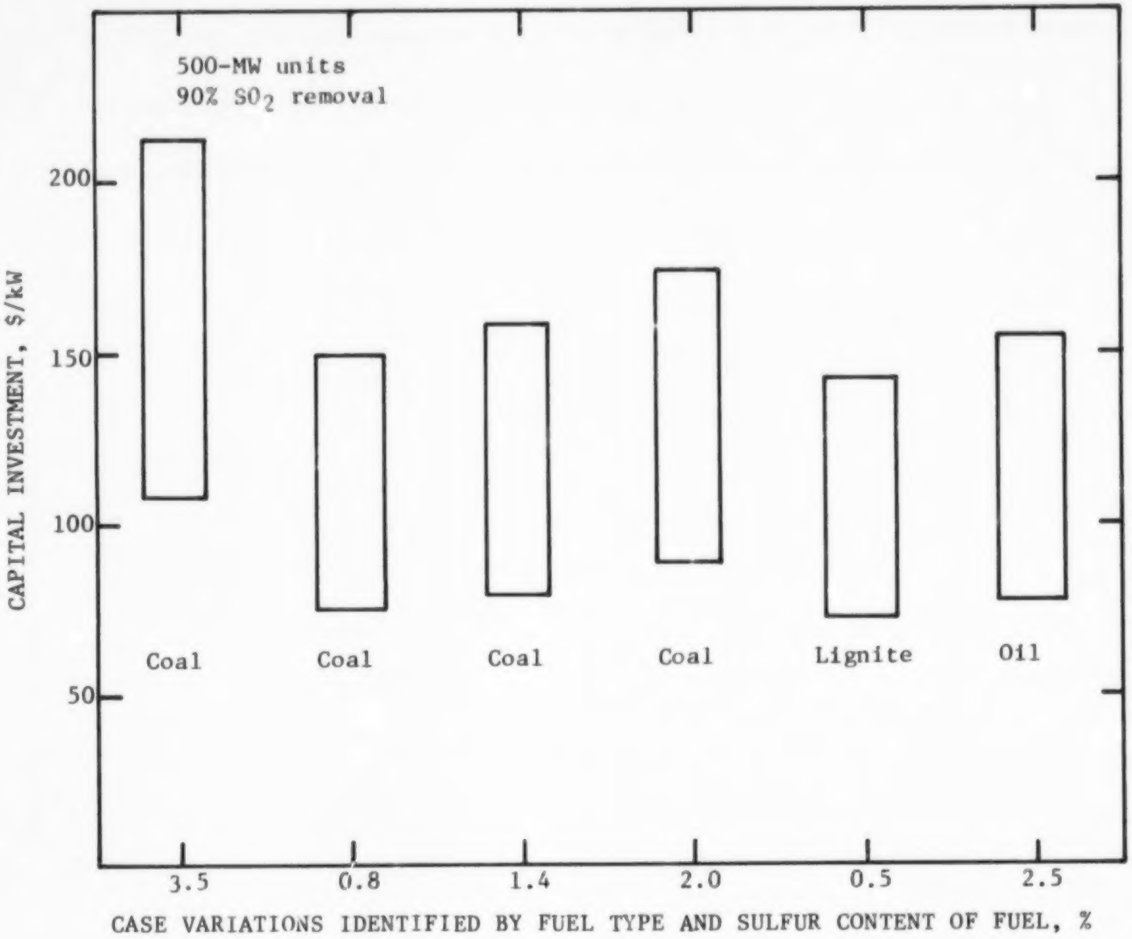

Figure I-2. Carbon adsorption process capital investment range.

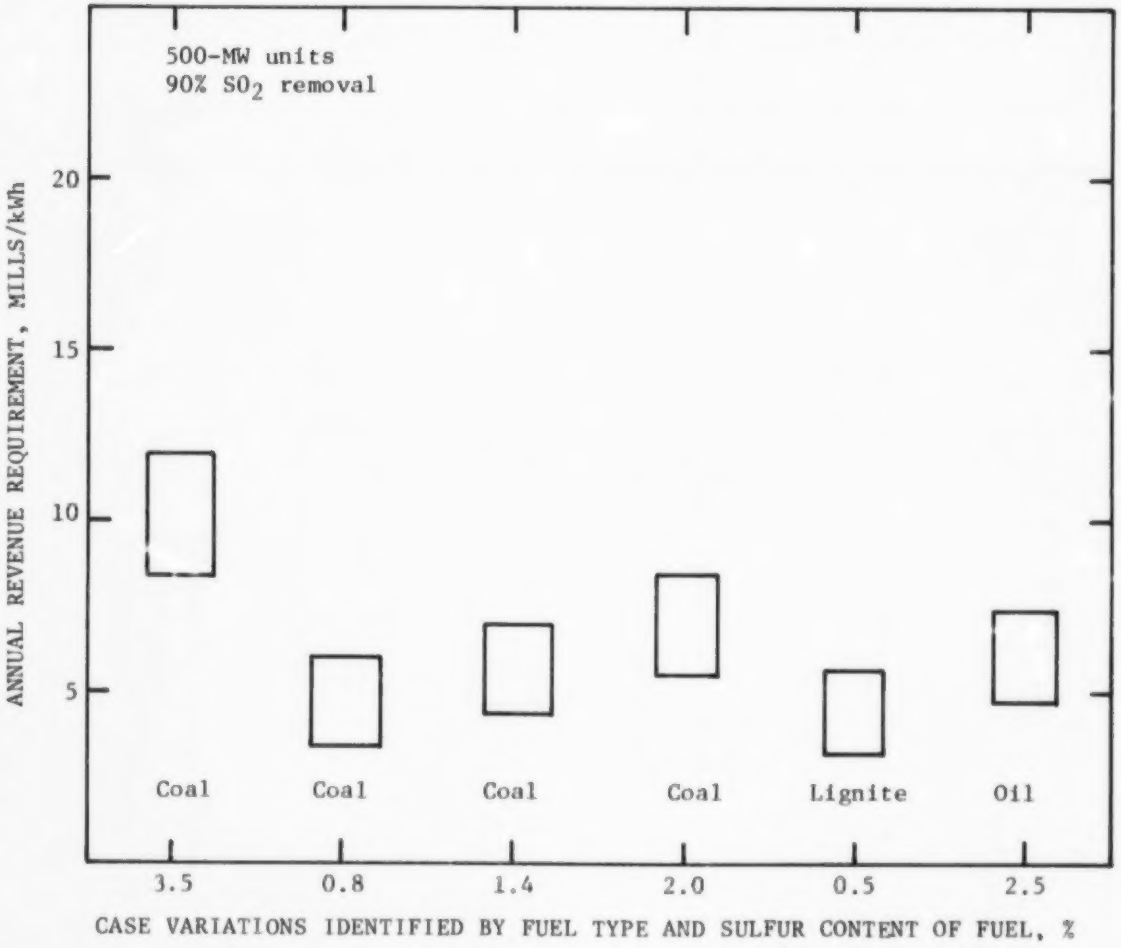

Figure I-3. Carbon adsorption process annual reverue requirements range.

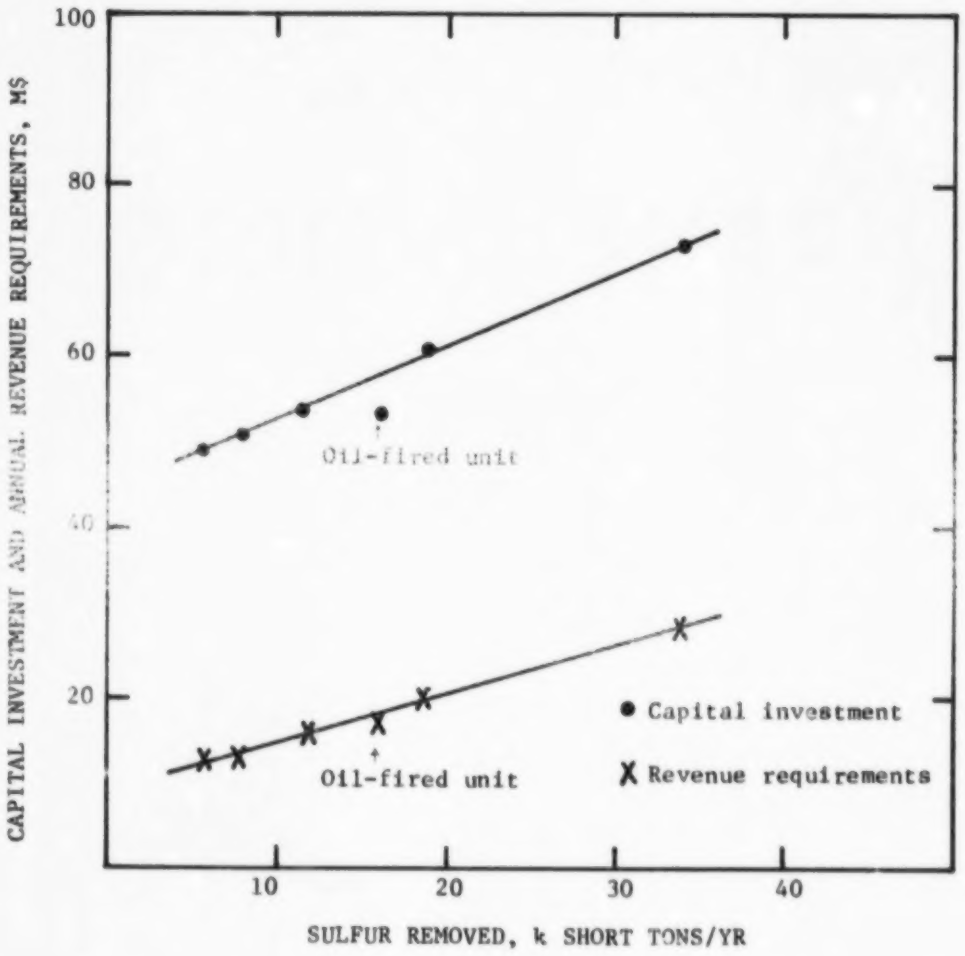

Figure I-4. Carbon adsorption process. Effect of sulfur removed on capital investment and annual revenue requirements.

TABLE I-6. CARBON ADSORPTION PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(500-MW new, coal-fired power unit,
3.5% sulfur in coal; 90% SO_2 removal; sulfur production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeders, silo, and bin)	2,132,000	6.0
Gas handling (common feed plenum and booster fans, gas ducts and dampers to adsorber, exhaust gas ducts and dampers from adsorber to stack)	3,970,000	11.1
SO_2 adsorption (four two-stage moving-bed adsorbers, feeders, conveyors, screens, elevators, and bins)	13,120,000	36.9
Regeneration and product gas treatment (bins, feeders, regenerators, tank, agitator, and pump)	1,675,000	4.7
Char cooling (two-stage char coolers, fan, conveyors, and elevators)	1,385,000	3.9
Sand heating (heater/elevators and blowers)	2,768,000	7.8
RESOX SO_2 reduction (reduction unit complete, battery limits)	7,800,000	21.9
Sulfur storage and shipping (tanks, heaters, and pumps)	727,000	2.0
Subtotal	33,577,000	94.3
Services, utilities, and miscellaneous	2,015,000	5.7
Total direct investment	35,592,000	100.0
Indirect Investment		
Engineering design and supervision	2,448,000	6.9
Architect and engineering contractor	612,000	1.7
Construction expense	4,848,000	13.6
Contractor fees	1,450,000	4.1
Total indirect investment	9,358,000	126.3
Contingency	8,990,000	25.3
Total fixed investment	53,940,000	151.6
Allowance for startup and modifications	5,394,000	15.1
Interest during construction	6,473,000	18.2
Total depreciable investment	65,807,000	184.9
Land	42,000	0.1
Working capital	3,507,000	9.8
Char charge	4,155,000	11.7
Total capital investment	73,511,000	206.5

Basis
Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Minimum in-process storage; only pumps are spared.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE I-7. CARBON ADSORPTION PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new, coal-fired power unit,
3.5% sulfur in coal; 90% SO_2 removal; sulfur production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net annual revenue requirements
Direct Costs				
Raw materials				
Sand	3,000 tons	7.50/ton	22,500	0.08
Char	15,600 tons	750.00/ton	11,700,000	41.07
Anthracite coal	33,300 tons	57.00/ton	1,898,100	6.66
Total raw materials cost			13,620,600	47.81
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	1.76
Utilities				
Fuel oil	4,917,800 gal	0.40/gal	1,967,100	6.90
Steam	15,600 MBtu	2.00/MBtu	31,200	0.11
Process water	40,500 kgal	0.12/kgal	4.900	0.02
Electricity	15,918,400 kWh	0.029/kWh	461,600	1.62
Heat credit	352,800 MBtu	2.00/MBtu	(705,600)	(2.48)
Maintenance				
Labor and material			2,491,400	8.75
Analyses	3,720 man-hr	17.00/man-hr	63,200	0.22
Total conversion costs			4,813,800	16.90
Total direct costs			18,434,400	64.71
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,948,400	13.86
Average cost of capital and taxes at 8.6% of total capital investment			6,321,900	22.19
Overheads				
Plant, 50% of conversion costs less utilities			1,527,300	5.36
Administrative, 10% of operating labor			50,000	0.18
Marketing, 10% of byproduct sales revenue			199,200	0.70
Total indirect costs			12,046,800	42.29
Gross annual revenue requirements			30,481,200	107.00
Byproduct Sales Revenue				
Elemental sulfur	32,700 tons	40.00/ton	(1,308,000)	(4.59)
RESOX waste coal	17,200 tons	26.50/ton	(455,800)	(1.61)
Adsorber char fines	12,000 tons	19.00/ton	(228,000)	(0.80)
Net annual revenue requirements			28,489,400	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements (net)	9.50	22.16	1.06	835

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,166,200 metric tons/yr (1,285,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Sulfur removed, 30,950 metric tons/yr (34,120 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $35,592,000; total depreciable investment, $65,807,000; and total capital investment, $73,511,000.
All tons shown are 2,000 lb.

TABLE I-8. CARBON ADSORPTION PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new, coal-fired power unit,
0.8% sulfur in coal, 90% SO_2 removal; sulfur production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeders, silo, and bin)	853,000	3.5
Gas handling (common feed plenum and booster fans, gas ducts and dampers to adsorber, exhaust gas ducts and dampers from adsorber to stack)	4,037,000	16.4
SO_2 adsorption (four two-stage moving-bed adsorbers, feeders, conveyors, screens, elevators, and bins)	13,369,000	54.5
Regeneration and product gas treatment (bins, feeders, regenerators, tank, agitator, and pump)	652,000	2.7
Char cooling (two-stage char coolers, fan, conveyors, and elevators)	508,000	2.1
Sand heating (heater/elevators and blowers)	1,016,000	4.1
RESOX SO_2 reduction (reduction unit complete, battery limits)	2,441,000	9.9
Sulfur storage and shipping (tanks, heaters, and pumps)	220,000	1.1
Subtotal	23,146,000	94.3
Services, utilities, and miscellaneous	1,389,000	5.7
Total direct investment	24,535,000	100.0
Indirect Investment		
Engineering design and supervision	1,644,000	6.7
Architect and engineering contractor	411,000	1.7
Construction expense	3,560,000	14.5
Contractor fees	1,093,000	4.4
Total indirect investment	6,708,000	27.3
Contingency	6,249,000	25.5
Total fixed investment	37,492,000	152.8
Allowance for startup and modifications	3,749,000	15.3
Interest during construction	4,499,000	18.3
Total depreciable investment	45,740,000	186.4
Land	42,000	0.2
Working capital	1,153.000	4.7
Char charge	4,260,000	17.4
Total capital investment	51,195,000	208.7

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE I-9. CARBON ADSORPTION PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new, coal-fired power unit,
0.8% sulfur in coal; 90% SO_2 removal; sulfur production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net annual revenue requirements
Direct Costs				
Raw materials				
Sand	700 tons	7.50/ton	5,300	0.04
Char	3,600 tons	750.00/ton	2,700,000	19.42
Anthracite coal	7,800 tons	57.00/ton	444,600	3.20
Total raw materials cost			3,149,900	22.66
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	3.60
Utilities				
Fuel oil	1,149,800 gal	0.40/gal	459,900	3.31
Steam	3,600 MBtu	2.00/MBtu	7,200	0.05
Process water	41,500 kgal	0.12/kgal	5,000	0.04
Electricity	10,199,000 kWh	0.029/kWh	295,800	2.13
Heat credit	82,500 MBtu	2.00/MBtu	(165,000)	(1.19)
Maintenance				
Labor and material			1,717,500	12.35
Analyses	1,560 man-hr	17.00/man-hr	26,500	0.19
Total conversion costs			2,846,900	20.48
Total direct costs			5,996,800	43.14
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,744,400	19.75
Average cost of capital and taxes at 8.6% of total capital investment			4,402,800	31.68
Overheads				
Plant, 50% of conversion costs less utilities			1,122,000	8.07
Administrative, 10% of operating labor			50,000	0.36
Marketing, 10% of byproduct sales revenue			46,300	0.33
Total indirect costs			8,365,500	60.19
Gross annual revenue requirements			14,362,300	103.33
Byproduct Sales Revenue				
Elemental sulfur	7,600 tons	40.00/ton	(304,000)	(2.19)
RESOX waste coal	40,200 tons	26.50/ton	(106,000)	(0.76)
Adsorber char fines	2,800 tons	19.00/ton	(53,200)	(0.38)
Net annual revenue requirements			13,899,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements (net)	4.63	9.78	0.51	1,742

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,288,900 metric tons/yr (1,421,100 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Sulfur removed, 7,240 metric tons/yr (7,980 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $24,535,000; total depreciable investment, $45,740,000; and total capital investment, $51,195,000.
All tons shown are 2,000 lb.

TABLE I-10. CARBON ADSORPTION PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new, coal-fired power unit,
1.4% sulfur in coal; 90% SO_2 removal; sulfur production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeders, silo, and bin)	1,096,000	4.2
Gas handling (common feed plenum and booster fans, gas ducts and dampers to adsorber, exhaust gas ducts and dampers from adsorber to stack)	3,942,000	15.1
SO_2 adsorption (four two-stage moving-bed adsorbers, feeders, conveyors, screens, elevators, and bins)	13,015,000	49.9
Regeneration and product gas treatment (bins, feeders, regenerators, tank, agitator, and pump)	843,000	3.2
Char cooling (two-stage char coolers, fan, conveyors, and elevators)	668,000	2.6
Sand heating (heater/elevators and blowers)	1,334,000	5.1
RESOX SO_2 reduction (reduction unit complete, battery limits)	3,346,000	12.8
Sulfur storage and shipping (tanks, heaters, and pumps)	354,000	1.4
Subtotal	24,598,000	94.3
Services, utilities, and miscellaneous	1,476,000	5.7
Total direct investment	26,074,000	100.0
Indirect Investment		
Engineering design and supervision	1,780,000	6.8
Architect and engineering contractor	445,000	1.7
Construction expense	3,744,000	14.4
Contractor fees	1,144,000	4.4
Total indirect investment	7,113,000	27.3
Contingency	6,638,000	25.5
Total fixed investment	39,825,000	152.8
Allowance for startup and modifications	3,983,000	15.3
Interest during construction	4,779,000	18.3
Total depreciable investment	48,587,000	186.4
Land	42,000	0.2
Working capital	1,473,000	5.6
Char charge	4,118,000	15.8
Total capital investment	54,220,000	208.0

Basis
- Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
- Minimum in-process storage; only pumps are spared.
- Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
- Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE I-11. CARBON ADSORPTION PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new, coal-fired power unit;
1.4% sulfur in coal; 90% SO_2 removal; sulfur production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net annual revenue requirements
Direct Costs				
Raw materials				
Sand	1,000 tons	7.50/ton	7,500	0.05
Char	5,400 tons	750.00/ton	4,050,000	25.63
Anthracite coal	11,600 tons	57.00/ton	661,200	4.18
Total raw materials cost			4,718,700	29.86
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	3.16
Utilities				
Fuel oil	1,149,800 gal	0.40/gal	459,900	2.91
Steam	5,400 MBtu	2.00/MBtu	10,800	0.07
Process water	40,100 kgal	0.12/kgal	4,800	0.03
Electricity	10,811,300 kWh	0.029/kWh	313,500	1.98
Heat credit	122,500 MBtu	2.00/MBtu	(245,000)	(1.55)
Maintenance				
Labor and material			1,825,200	11.55
Analyses	1,970 man-hr	17.00/man-hr	33,500	0.21
Total conversion costs			2,902,700	18.36
Total direct costs			7,621,400	48.22
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,915,200	18.4[illegible]
Average cost of capital and taxes at 8.6% of total capital investment			4,662,900	29.51
Overheads				
Plant, 50% of conversion costs less utilities			1,179,400	7.46
Administrative, 10% of operating labor			50,000	0.32
Marketing, 10% of byproduct sales revenue			69,500	0.44
Total indirect costs			8,877,000	56.18
Gross annual revenue requirements			16,498,400	104.40
Byproduct Sales Revenue				
Elemental sulfur	11,400 tons	40.00/ton	(456,000)	(2.89)
RESOX waste coal	6,000 tons	26.50/ton	(159,000)	(1.01)
Adsorber char fines	4,200 tons	19.00/ton	(79,800)	(0.50)
Net annual revenue requirements			15,803,600	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements (net)	5.27	14.75	0.59	1,334

Basis
- 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 6,000 hr/yr.
- Coal burned, 971,900 metric tons/yr (1,071,600 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
- Sulfur removed, 10,750 metric tons/yr (11,850 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $26,074,000; total depreciable investment, $48,587,000; and total capital investment, $[illegible],220,000.
- All tons shown are 2,[illegible] lb.

TABLE I-12. CARBON ADSORPTION PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new, coal-fired power unit,
2.0% sulfur in coal; 90% SO_2 removal; sulfur production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeders, silo, and bin)	1,465,000	5.0
Gas handling (common feed plenum and booster fans, gas ducts and dampers to adsorber, exhaust gas ducts and dampers from adsorber to stack)	3,954,000	13.5
SO_2 adsorption (four two-stage moving-bed adsorbers, feeders, conveyors, screens, elevators, and bins)	13,068,000	44.5
Regeneration and product gas treatment (bins, feeders, regenerators, tank, agitator, and pump)	1,137,000	3.9
Char cooling (two-stage char coolers, fan, conveyors, and elevators)	918,000	3.1
Sand heating (heater/elevators and blowers)	1,835,000	6.2
RESOX SO_2 reduction (reduction unit complete, battery limits)	4,836,000	16.5
Sulfur storage and shipping (tanks, heaters, and pumps)	485,000	1.6
Subtotal	27,698,000	94.3
Services, utilities, and miscellaneous	1,662,000	5.7
Total direct investment	29,360,000	100.0
Indirect Investment		
Engineering design and supervision	2,004,000	6.8
Architect and engineering contractor	501,000	1.7
Construction expense	4,132,000	14.1
Contractor fees	1,252,000	4.3
Total indirect investment	7,889,000	26.9
Contingency	7,450,000	25.4
Total fixed investment	44,699,000	152.3
Allowance for startup and modifications	4,470,000	15.2
Interest during construction	5,364,000	18.3
Total depreciable investment	54,533,000	185.8
Land	42,000	0.1
Working capital	2,126,000	7.2
Char charge	4,133,000	14.1
Total capital investment	60,834,000	207.2

Basis
Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Minimum in-process storage; only pumps are spared.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE I-13. CARBON ADSORPTION PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new, coal-fired power unit;
2.0% sulfur in coal; 90% SO_2 removal; sulfur production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net annual revenue requirements
Direct Costs				
Raw materials				
Sand	1,700 tons	7.50/ton	12,800	0.06
Char	8,600 tons	750.00/ton	6,450,000	32.28
Anthracite coal	18,300 tons	57.00/ton	1,043,100	5.22
Total raw materials cost			7,505,900	37.56
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	2.50
Utilities				
Fuel oil	2,708,200 gal	0.40/gal	1,083,300	5.42
Steam	8,600 MBtu	2.00/MBtu	17,200	0.09
Process water	40,300 kgal	0.12/kgal	4,800	0.02
Electricity	10,165,000 kWh	0.029/kWh	294,800	1.48
Heat credit	194,300 MBtu	2.00/MBtu	(388,600)	(1.94)
Maintenance				
Labor and material			2,055,200	10.28
Analyses	2,600 man-hr	17.00/man-hr	44,200	0.22
Total conversion costs			3,610,900	18.07
Total direct costs			11,116,800	55.63
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,272,000	16.37
Average cost of capital and taxes at 8.6% of total capital investment			5,231,700	26.18
Overheads				
Plant, 50% of conversion costs less utilities			1,299,700	6.50
Administrative, 10% of operating labor			50,000	0.25
Marketing, 10% of byproduct sales revenue			109,700	0.55
Total indirect costs			9,963,100	49.85
Gross annual revenue requirements			21,079,900	105.48
Byproduct Sales Revenue				
Elemental sulfur	18,000 tons	40.00/ton	(720,000)	(3.60)
RESOX waste coal	9,500 tons	26.50/ton	(251,800)	(1.25)
Adsorber char fines	6,600 tons	19.00/ton	(125,400)	(0.63)
Net annual revenue requirements			19,982,700	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ ton sulfur removed
Equivalent unit revenue requirements (net)	6.66	16.28	0.74	1,063

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Coal burned, 1,113,200 metric tons/yr (1,227,300 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Sulfur removed, 17,040 metric tons/yr (18,790 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $29,360,000; total depreciable investment, $54,533,000; and total capital investment, $60,834,000.
All tons shown are 2,000 lb.

TABLE I-14. CARBON ADSORPTION PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new, lignite-fired power unit, 0.5% sulfur in lignite;
90% SO_2 removal; sulfur production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeders, silo, and bin)	699,000	2.9
Gas handling (common feed plenum and booster fans, gas ducts and dampers to adsorber, exhaust gas ducts and dampers from adsorber to stack)	4,105,000	17.4
SO_2 adsorption (four two-stage moving-bed adsorbers, feeders, conveyors, screens, elevators, and bins)	13,645,000	57.7
Regeneration and product gas treatment (bins, feeders, regenerators, tank, agitator, and pump)	529,000	2.3
Char cooling (two-stage char coolers, fan, conveyors, and elevators)	409,000	1.7
Sand heating (heater/elevators and blowers)	817,000	3.4
RESOX SO_2 reduction (reduction unit complete, battery limits)	1,895,000	8.0
Sulfur storage and shipping (tanks, heaters, and pumps)	218,000	0.9
Subtotal	22,317,000	94.3
Services, utilities, and miscellaneous	1,339,000	5.7
Total direct investment	23,656,000	100.0
Indirect Investment		
Engineering design and supervision	1,563,000	6.6
Architect and engineering contractor	391,000	1.6
Construction expense	3,454,000	14.6
Contractor fees	1,063,000	4.5
Total indirect investment	6,471,000	27.3
Contingency	6,025,000	25.5
Total fixed investment	36,152,000	152.8
Allowance for startup and modifications	3,615,000	15.3
Interest during construction	4,338,000	18.3
Total depreciable investment	44,105,000	186.4
Land	42,000	0.2
Working capital	973,000	4.1
Char charge	4,365,000	18.5
Total capital investment	49,485,000	209.2

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE I-15. CARBON ADSORPTION PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new, lignite-fired power unit;
0.5% sulfur in lignite; 90% SO_2 removal; sulfur production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net annual revenue requirements
Direct Costs				
Raw materials				
Sand	500 tons	7.50/ton	3,800	0.03
Char	2,700 tons	750.00/ton	2,025,000	15.84
Anthracite coal	5,700 tons	57.00/ton	324,900	2.54
Total raw materials cost			2,353,700	18.41
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	3.91
Utilities				
Fuel oil	837,500 gal	0.40/gal	335,000	2.62
Steam	2,700 MBtu	2.00/MBtu	5,400	0.04
Process water	42,600 kgal	0.12/kgal	5,100	0.04
Electricity	9,911,000 kWh	0.029/kWh	287,400	2.25
Heat credit	60,100 MBtu	2.00/MBtu	(120,200)	(0.94)
Maintenance				
Labor and material			1,655,900	12.96
Analyses	1,290 man-hr	17.00/man-hr	21,900	0.17
Total conversion costs			2,690,500	21.05
Total direct costs			5,044,200	39.46
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,646,300	20.71
Average cost of capital and taxes at 8.6% of total capital investment			4,255,700	33.30
Overheads				
Plant, 50% of conversion costs less utilities			1,088,900	8.52
Administrative, 10% of operating labor			50,000	0.39
Marketing, 10% of byproduct sales revenue			33,900	0.27
Total indirect costs			8,074,800	63.19
Gross annual revenue requirements			13,119,000	102.65
Byproduct Sales Revenue				
Elemental sulfur	5,600 tons	40.00/ton	(224,000)	(1.75)
RESOX waste coal	2,900 tons	26.50/ton	(76,900)	(0.60)
Adsorber char fines	2,000 tons	19.00/ton	(38,000)	(0.30)
Net annual revenue requirements			12,780,100	100.00

	Mills/kWh	$/ton lignite burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements (net)	4.26	7.48	0.47	2,200

Basis
1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 6,000 hr/yr.
Lignite burned, 1,549,900 metric tons/yr (1,708,800 tons/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
Sulfur removed, 5,271 metric tons/yr (5,810 short tons/yr).
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $23,656,000; total depreciable investment, $44,105,000; and total capital investment, $49,485,000.
All tons shown are 2,000 lb.

TABLE I-16. CARBON ADSORPTION PROCESS

SUMMARY OF CAPITAL INVESTMENT

(500-MW new, oil-fired power unit,
2.5% sulfur in oil; 90% SO_2 removal; sulfur production)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, elevators, feeders, silo, and bin)	1,305,000	5.1
Gas handling (common feed plenum and booster fans, gas ducts and dampers to adsorber, exhaust gas ducts and dampers from adsorber to stack)	3,506,000	13.6
SO_2 adsorption (four two-stage moving-bed adsorbers, feeders, conveyors, screens, elevators, and bins)	11,349,000	44.0
Regeneration and product gas treatment (bins, feeders, regenerators, tank, agitator, and pump)	1,025,000	4.0
Char cooling (two-stage char coolers, fan, conveyors, and elevators)	823,000	3.2
Sand heating (heater/elevators and blowers)	1,644,000	6.4
RESOX SO_2 reduction (reduction unit complete, battery limits)	4,259,000	16.5
Sulfur storage and shipping (tanks, heaters, and pumps)	435,000	1.7
Subtotal	24,346,000	94.3
Services, utilities, and miscellaneous	1,461,000	5.7
Total direct investment	25,807,000	100.0
Indirect Investment		
Engineering design and supervision	1,917,000	7.4
Architect and engineering contractor	479,000	1.9
Construction expense	3,713,000	14.4
Contractor fees	1,136,000	4.4
Total indirect investment	7,245,000	28.1
Contingency	6,610,000	25.6
Total fixed investment	39,662,000	153.7
Allowance for startup and modifications	3,966,000	15.4
Interest during construction	4,759,000	18.4
Total depreciable investment	48,387,000	187.5
Land	42,000	0.2
Working capital	1,843,000	7.1
Char charge	3,458,000	13.4
Total capital investment	53,730,000	208.2

Basis
- Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
- Minimum in-process storage; only pumps are spared.
- Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
- Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE I-17. CARBON ADSORPTION PROCESS

SUMMARY OF ANNUAL REVENUE REQUIREMENTS

(500-MW new, oil-fired power unit;
2.5% sulfur in oil; 90% SO_2 removal; sulfur production)

	Annual quantity	Unit cost, $	Total annual cost, $	% of net annual revenue requirements
Direct Costs				
Raw materials				
Sand	1,400 tons	7.50/ton	10,500	0.06
Char	7,300 tons	750.00/ton	5,475,000	31.21
Anthracite coal	15,600 tons	57.00/ton	889,200	5.07
Total raw materials cost			6,374,700	36.34
Conversion costs				
Operating labor and supervision	40,000 man-hr	12.50/man-hr	500,000	2.85
Utilities				
Fuel oil	2,308,900 gal	0.40/gal	923,600	5.27
Steam	7,300 MBtu	2.00/MBtu	14,600	0.08
Process water	33,700 kgal	0.12/kgal	4,000	0.02
Electricity	10,555,000 kWh	0.029/kWh	306,100	1.74
Heat credit	165,600 MBtu	2.00/MBtu	(331,200)	(1.89)
Maintenance				
Labor and material			1,806,500	10.30
Analyses	2,360 man-hr	17.00/man-hr	40,100	0.23
Total conversion costs			3,263,700	18.60
Total direct costs			9,638,400	54.94
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,903,200	16.55
Average cost of capital and taxes at 8.6% of total capital investment			4,620,700	26.34
Overheads				
Plant, 50% of conversion costs less utilities			1,173,300	6.69
Administrative, 10% of operating labor			50,000	0.29
Marketing, 10% of byproduct sales revenue			93,700	0.53
Total indirect costs			8,840,900	50.40
Gross annual revenue requirements			18,479,300	105.34
Byproduct Sales Revenue				
Elemental sulfur	15,400 tons	40.00/ton	(616,000)	(3.51)
RESOX waste coal	8,100 tons	26.50/ton	(214,700)	(1.22)
Adsorber char fines	5,600 tons	19.00/ton	(106,400)	(0.61)
Net annual revenue requirements			17,542,200	100.00

	Mills/kWh	$/bbl oil burned	$/MBtu heat input	$/ton sulfur removed
Equivalent unit revenue requirements (net)	5.85	3.93	0.65	1,095

Basis
- 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 6,000 hr/hr.
- Oil burned, 710 x 10^6 liters/yr (4,464,300 bbl/yr), 2,268 kcal/kWh (9,000 Btu/kWh).
- Sulfur removed, 14,533 metric tons/yr (16,020 short tons/yr).
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $25,807,000; total depreciable investment, $48,387,000; and total capital investment, $53,730,000.
- All tons shown are 2,000 lb.

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